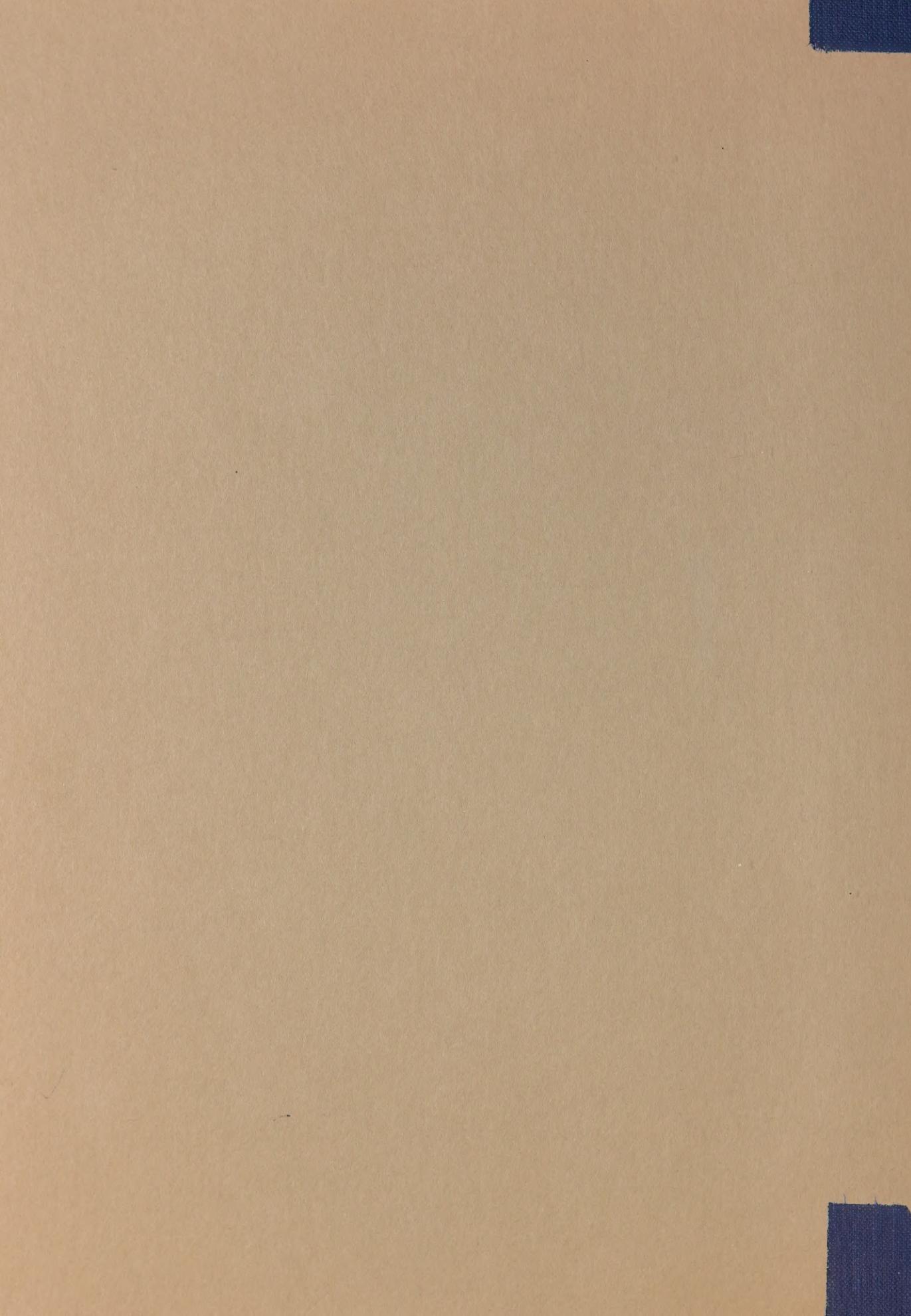




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# NATIONAL ENERGY BOARD

## REPORT TO

## THE GOVERNOR IN COUNCIL

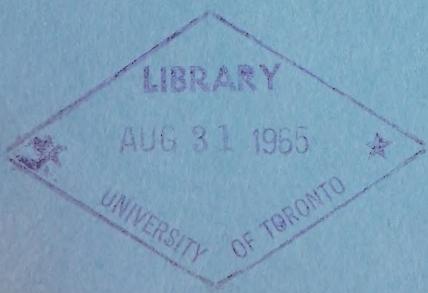
In the Matter of the Application under  
The National Energy Board Act of

*Alberta and Southern Gas Co. Ltd.*

*Alberta Natural Gas Company*

*Canadian - Montana Pipe Line Company*

*Trans - Canada Pipe Lines Limited*





NATIONAL ENERGY BOARD

Report to

The Governor in Council

In the Matter of the Applications under

the National Energy Board Act

of

ALBERTA AND SOUTHERN GAS CO. LTD.  
ALBERTA NATURAL GAS COMPANY  
CANADIAN-MONTANA PIPE LINE COMPANY  
TRANS-CANADA PIPE LINES LIMITED

July 1965



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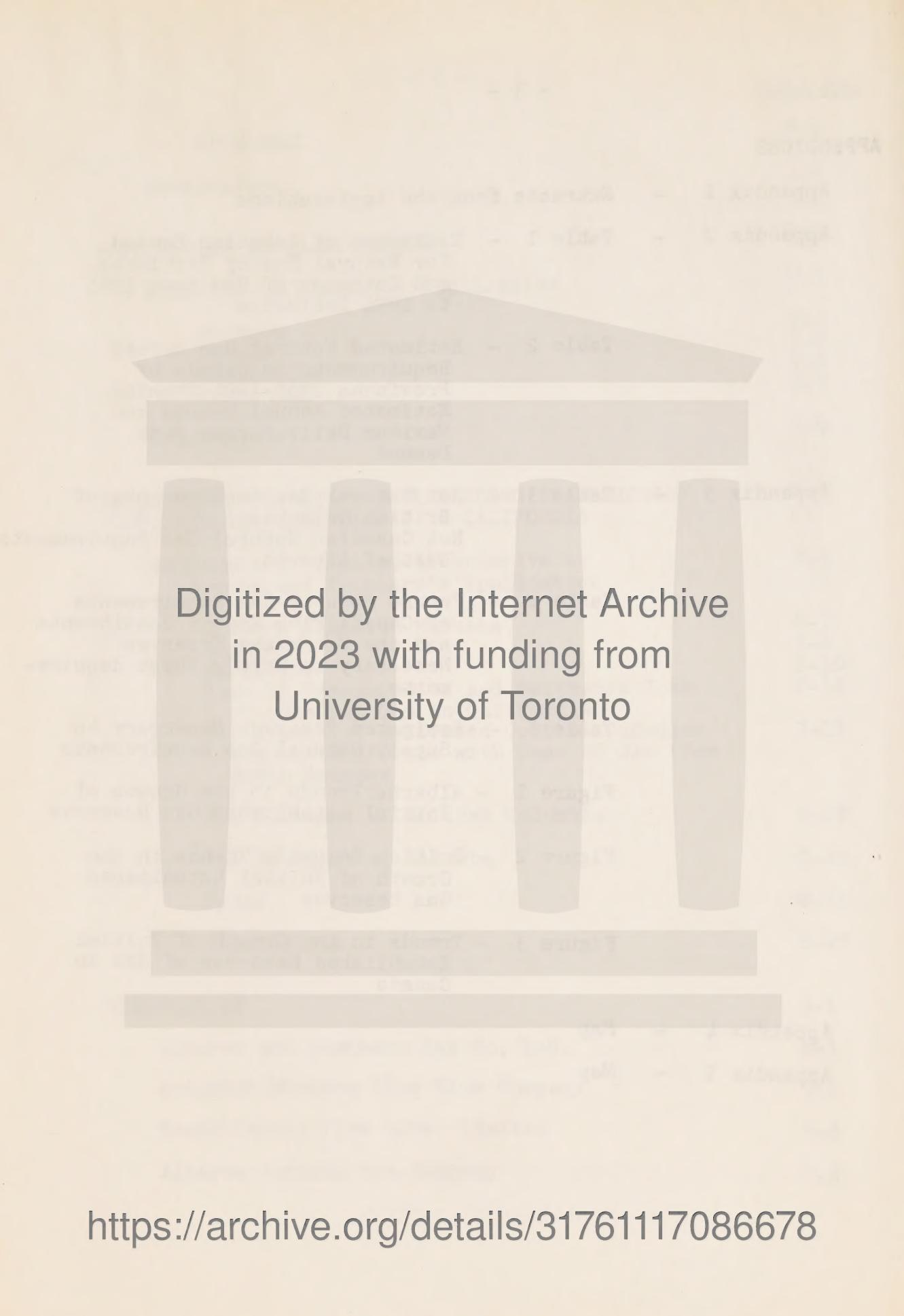
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NATIONAL ENERGY BOARD

IN THE MATTER OF an application of Alberta and Southern Gas Co. Ltd. for:

- (1) An order of the Board pursuant to Part VI and Section 17 of the National Energy Board Act to vary subsisting Licence GL-3.
- (2) A licence pursuant to Part VI of the said Act for the exportation of gas at a place on the international boundary between Canada and the United States of America near Kingsgate in the Province of British Columbia, and

IN THE MATTER OF an application of Alberta Natural Gas Company for:

- (1) An order of the Board pursuant to Part III and Section 17 of the National Energy Board Act to vary subsisting Certificate GC-12.
- (2) A certificate under Part III or an order under Section 49 of the said Act to construct and operate certain additional pipe line facilities on its existing pipe line system, and

IN THE MATTER OF an application of Canadian-Montana Pipe Line Company for:

- (1) An order of the Board pursuant to Part VI and Section 17 of the National Energy Board Act to vary subsisting Licence GL-5.
- (2) A licence pursuant to Part VI of the said Act for the exportation of gas at a place on the international boundary between Canada and the United States of America in Section 4, Township 1, Range 25, west of the 4th Meridian in the Province of Alberta, and

IN THE MATTER OF an application of Trans-Canada Pipe Lines Limited for:

A licence pursuant to Part VI of the National Energy Board Act for the exportation of gas at a place on the international border between Canada and the United States of America near Emerson in the Province of Manitoba.

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HEARD at Ottawa, Ontario, on 29, 30 and 31 March, 1, 2, 5, 6,  
7, 8, 9 April, 1965.

BEFORE:

I.N. McKinnon, Chairman  
Douglas M. Fraser, Member  
Maurice Royer, Member

APPEARANCES:

R.A. MacKimmie, Q.C.	for Alberta and Southern Gas Co. Ltd. and Alberta Natural Gas Company
K.E. Eaton	for Canadian-Montana Pipe Line Company
N.J. McNeill, Q.C.) F.J. Layton, Q.C. ) R.J. Ludgate )	for Trans-Canada Pipe Lines Limited
J.M. Robertson, Q.C.) J.J. Frawley, Q.C. )	for the Province of Alberta
C.W. Brazier, Q.C. ) J.T. Alley )	for the Province of British Columbia
Arthur Patillo, Q.C.) D.P. McDonald, Q.C. )	for Westcoast Transmission Company Limited
D.W. MacFarlane	for Canadian Petroleum Association
R.C. Muir	for British American Oil Company Limited
J. Anderson	for Pacific Petroleums Limited
F.H.J. Lamar J.M. Hendry )	for the National Energy Board

## APPLICATIONS\*

Alberta and Southern Gas Co. Ltd.

Alberta and Southern Gas Co. Ltd. ("Alberta and Southern") is a company incorporated under the laws of the Province of Alberta. It is a wholly-owned subsidiary of Pacific Gas and Electric Company ("PG&E") of San Francisco which distributes gas in the northern part of the State of California. Alberta and Southern is authorized, under Licence GL-3 issued by the Board on 11 April 1960, to export up to 459 million cubic feet of gas a day (MMcf/d) over a period expiring 31 October 1986. This gas, which is purchased in Alberta from various producers, is transported for Alberta and Southern through the facilities of The Alberta Gas Trunk Line Company Limited ("Trunk Line") to the Alberta-British Columbia boundary. It is then transported to the international border at Kingsgate, British Columbia, through the facilities of Alberta Natural Gas Company ("Alberta Natural"), a company controlled by Pacific Gas Transmission Company ("PGT") which is in turn controlled by PG&E. At this point the gas is sold by Alberta and Southern to PGT which transports it to the California border and resells the gas to PG&E.

Alberta and Southern also sells gas to Canadian-Montana Pipe Line Company which in turn exports it to its parent company, The Montana Power Company, for sale in markets served by the latter in Montana.

\*Full details of the applications are set forth in Appendix 1.

Alberta and Southern proposes in the application now before the Board to increase its exports to PG&E and for this purpose has entered into a supplemental agreement with PGT whereby the latter undertakes to buy from Alberta and Southern an additional average 103 MMcf/d commencing 1 November 1966, rising to 207 MMcf/d on or about 1 November 1967.

Accordingly, Alberta and Southern has applied for a further licence under Part VI of the National Energy Board Act for the exportation of gas near Kingsgate for a period commencing on the day of its issue and ending on 31 October 1989. The maximum quantity of gas to be exported contemporaneously under Licence GL-3 and the requested new licence would be 685 MMcf/d, 228 billion cubic feet (Bcf) per annum and 5.9 trillion cubic feet (Tcf) during the term of the licence. Alberta and Southern has also applied for an Order of the Board pursuant to the provisions of Part VI and of Section 17 of the Act to vary Licence GL-3.

Alberta Natural Gas Company

Alberta Natural is a company incorporated by Special Act of the Parliament of Canada. Its facilities consist of a 36-inch pipe line system connecting the facilities of Trunk Line with those of PGT, and are authorized by Certificate of

Public Convenience and Necessity GC-12, issued by the Board on 19 April 1960, as amended by AO-1-GC-12, dated 9 September 1960 and AO-2-GC-12 dated 24 November 1960. To facilitate the proposed additional export by Alberta and Southern, Alberta Natural has applied to the Board for an Order pursuant to Part III and Section 17 of the Act to vary Certificate GC-12, as amended, for the purpose of clarifying references to the pipe line facilities certificated and their design data, etc. and for a further Certificate or an Order under Section 49 of the Act to construct and operate a new compressor station, two additional compressor units at an existing station and certain additional metering facilities, altogether estimated to cost \$5,383,000.

Canadian-Montana Pipe Line Company

Canadian-Montana Pipe Line Company ("Canadian-Montana") is a company incorporated by Special Act of the Parliament of Canada and is the holder of Licence GL-5, issued by the Board on 11 April 1960, authorizing the export of up to 36 MMcf/d of gas at a point on the international boundary near Cardston, Alberta, to Montana Power Company ("Montana Power") over a period ending 31 October 1986. All of the gas exported under this licence is purchased from Alberta and Southern, on whose account it is collected in Alberta by Trunk Line and transported through its facilities to a point in southwestern Alberta where it enters the 16-inch pipe line of Canadian-Montana,

authorized by Certificate GC-13 issued by the Board on 19 April 1960, to travel some three miles to the point of sale to Montana Power at the international boundary.

Canadian-Montana has entered into a supplemental agreement dated 21 May 1964 to purchase from Alberta and Southern an additional average daily quantity of 10 MMcf, commencing 1 November 1966, rising to 20 MMcf on or about 1 November 1967, for sale to Montana Power. No additional pipe line facilities would be required to transmit these additional volumes.

Canadian-Montana has applied for a further licence under Part VI for the export of additional quantities of gas to Montana Power for a period commencing on the day of issue and ending 31 October 1989. The maximum quantity of gas to be exported contemporaneously under Licence GL-5 and the requested new Licence would be 60 MMcf/d, 18.25 Bcf per annum and 416.1 Bcf during the term of the Licence. Canadian-Montana has also applied to the Board for an Order pursuant to Part VI and Section 17 of the Act to vary Licence GL-5.

#### Trans-Canada Pipe Lines Limited

Trans-Canada Pipe Lines Limited ("Trans-Canada"), a company incorporated by Special Act of the Parliament of Canada, operates a large diameter pipe line system from the

Alberta-Saskatchewan border to Montreal. One of the system's three main laterals, a 50-mile 30-inch line, extends from a point near Winnipeg to a point on the international boundary near Emerson, Manitoba, where it connects with the pipe line of Midwestern Gas Transmission Company ("Midwestern"). Trans-Canada is authorized to export at Emerson, under Licence GL-1 issued by the Board on 11 April 1960, up to 204 MMcf/d to Midwestern over a period ending 14 May 1981.

By the terms of Trans-Canada's contract with Midwestern of 14 April 1960 the latter has an exclusive irrevocable preferential right and option ("Midwestern option") to purchase at Emerson such additional quantities of gas per day as Trans-Canada is authorized to export from time to time along the international border between the eastern boundary of Alberta and Lake Superior up to an aggregate additional quantity of 204 MMcf/d. By Order A0-1-GL-1, issued by the Board on 4 August 1964, the maximum daily quantity permitted to be exported under GL-1 was increased to 223 MMcf but the annual and aggregate quantities were not altered. This change reduced the daily maximum subject to the option to 186 MMcf/d.

To satisfy the balance of the option, Trans-Canada, in the application before the Board, requests a further licence under Part VI to export, for a 25-year period commencing 1 November 1965, not more than 186 MMcf/d, nor 68 Bcf in any

consecutive 12-month period, nor 1.7 Tcf during the term of the licence, which gas it would offer to Midwestern.

Additional facilities would be required to transport any increased volumes of gas of which export is authorized, but as the volume of additional gas which Midwestern might be interested in contracting for had not been established at the time of the hearing the extent of the additional facilities required was unknown. Subsequent applications would be made as facilities became necessary.

Additional Volumes of Gas  
for which Export Licences are Requested

<u>Applicant</u>	<u>Volumes</u>			<u>Period</u>
	<u>Maximum</u>			
	<u>Day</u>	<u>Annual</u> (millions of cubic feet)	<u>Total</u>	
Alberta and Southern	226.3	74,830	1,389,700	From date of issue of licence to 31/10/86
	685.0	228,100	684,300	From 1/11/86 to 31/10/89
			<u>2,074,000</u>	
Canadian-Montana	24.0	7,300	87,600	From date of issue of licence to 31/10/86
	60.0	18,250	54,750	From 1/11/86 to 31/10/89
			<u>142,350</u>	
Trans-Canada	186.0	68,000	1,700,000	From 1/11/65 to 31/10/90

NOTE: All volumes of gas in this report, unless otherwise specified, refer to measurement at standard conditions of 14.73 psia pressure base and 60°F temperature base.



## JOINT HEARING

Pursuant to Section 83 of the Act the Board, in considering an application for the export of gas, is required to satisfy itself, inter alia, that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada. In fulfilling this statutory responsibility the Board is obliged to estimate the requirements for gas in Canadian markets over a reasonably foreseeable future period, to estimate gas reserves in Canada, to assess the trends in gas discovery, and to determine whether there is sufficient gas to protect Canadian requirements, and if so, whether any surplus is sufficient to support the proposed export.

Since the question of surplus is a matter of concern to all three applicants, the Board, with their consent, directed that the evidence relating to gas reserves and deliverabilities and foreseeable gas requirements for use in Canada be consolidated. By agreement each applicant submitted its estimates of Canadian requirements of gas reserves and deliverabilities, and of trends and surplus, before presenting the balance of its particular application.



## INTERVENTIONS

Westcoast Transmission Company Limited ("Westcoast") and the Province of British Columbia opposed the application of Alberta and Southern. These Intervenors did not oppose the export of gas from Canada but rather contended that any additional gas to be exported to California at this time should come from British Columbia rather than from Alberta. This proposal was strongly criticized by the Province of Alberta, which also intervened, generally in favour of additional gas exports and the present applications and against the position taken by the Province of British Columbia.

Westcoast at the present time sells gas to El Paso Natural Gas Company ("El Paso") at a point of interconnection on the international border near Sumas, Washington. In its intervention Westcoast proposed that Alberta and Southern should purchase British Columbia gas from Westcoast at Sumas and transport it through El Paso's northwest facilities to a point of interconnection with the PGT line at Stanfield near Pendleton, Oregon, where it would be mixed with the Alberta gas already moving in that pipe line system. Evidence both for and against this proposal is dealt with in section 8 of this Report.

The Canadian Petroleum Association ("CPA") filed an intervention containing a general recommendation in favour

of the export of natural gas which was over and above the reasonably foreseeable requirements of Canadian markets. It also provided data on natural gas reserves in Canada and a submission as to the benefits to Canada from additional exports of natural gas.

The British American Oil Company Limited ("BA") filed a notice of intervention supporting the applications of Alberta and Southern and Trans-Canada. At the same time it made a submission as to established reserves of gas and trends in growth of reserves in Western Canada.

Each of the Applicants filed a notice of intervention in the other applications indicating that it did so chiefly for the purpose of being in a position to cross-examine witnesses placing evidence before the Board. Notices of intervention for essentially the same purpose were filed by Pacific Petroleum Ltd. and The Consumers' Gas Company, although the latter withdrew its intervention prior to the hearing.

Representations and evidence submitted by Intervenors are dealt with in the appropriate sections of this Report.

In addition to the formal interventions in respect of which appearances were made at the hearing, letters were received from the Independent Petroleum Association of Canada supporting the applications and from the British Columbia &

Yukon Chamber of Mines, British Columbia Chamber of Commerce and the Vancouver Board of Trade opposing the export of Alberta gas to California and in favour of the export of British Columbia gas. Letters were also received from a number of individuals commenting on various aspects of the applications.



## CANADIAN REQUIREMENTS AND SUPPLY

Canadian Requirements - Evidence

Alberta and Southern and Trans-Canada provided detailed estimates of annual requirements for 30-year periods, ending 31 December 1994 and 31 December 1993 respectively, for each province served with natural gas. Alberta and Southern forecast peak-day requirements for each of the first five years and at intervals of five years thereafter to 1989. Trans-Canada provided estimates of peak-day requirements annually throughout the forecast period.

For the 30-year period, Alberta and Southern forecast a total Canadian requirement of 35.9 Tcf whereas Trans-Canada's estimate totalled 39.0 Tcf\*.

The sum of the peak demands estimated by province was forecast by Alberta and Southern as 7,440 MMcf/d in 1989, the last year for which it provided a peak-day, and by Trans-Canada as 7,116 MMcf/d for the same year.

For 1989 annual requirements were estimated by Alberta and Southern to total 1.6 Tcf and by Trans-Canada 1.8 Tcf. Differences between the Applicants' forecasts of industrial sales in Alberta and Ontario accounted for the spread.

Estimates of residential and commercial use by Alberta and Southern and Trans-Canada were similar in volumes forecast and in rates of growth. In the industrial sector greater differences were noted between these forecasts. However, both estimates included allowance for gas requirements

\*Requirements figures are on a basis of 1,000 Btu's per cubic foot.

of an iron and steel industry expected to be developed in Northern Alberta and for the rapid growth in the potash industry of Saskatchewan. The forecasts included, inter alia, volumes estimated for service extensions to Vancouver Island, Sault Ste. Marie and Rouyn-Noranda.

Competition from other sources of energy, particularly from electricity for the space heating market, was not considered by either Applicant; it was their view that it was preferable to overstate Canadian gas requirements rather than to attempt precise forecasts of shifts in the balance of inter-fuel competition.

Alberta and Southern, in preparing its estimates, relied on an independent study by Foster Associates Ltd. under date of 5 October 1964. This provided a forecast of annual natural gas requirements by province and peak-day demand quantities, assuming coincident peak demands by the utility customers in each province.

Trans-Canada derived its estimate of British Columbia requirements from that submitted by Westcoast to the Board in 1964. Trans-Canada adopted as a basis for Alberta gas requirements, those forecast by the Oil and Gas Conservation Board of Alberta ("Alberta Board") in its report to the Lieutenant Governor in Council ("Alberta Board report") of November 1964. The estimate of requirements for Saskatchewan was derived from an estimate presented to the Saskatchewan

Resources Conference on 20 January 1964, by the General Manager of the Saskatchewan Power Corporation. Trans-Canada's estimates of peak-day demand in areas it serves in Manitoba, Ontario and Quebec were based on daily demand on the pipe line rather than maximum distributors' sales.

In testifying as to Canadian requirements, Westcoast confined itself to the Province of British Columbia. This Company included inter alia detailed estimates for service to Vancouver Island and for increased industrial sales to Inland Natural Gas Company ("Inland"). These estimates had been included by Westcoast in a submission to the Board at a hearing in 1964 under the classification "Unallocated"; this had also included projected additional exports to the United States Pacific Northwest. In its current submission Westcoast substituted, for such proposed exports, larger volumes to be supplied to Alberta and Southern for the California market in place of Alberta gas.

Westcoast had not included in its forecast the Prince Rupert market. It hoped to supply natural gas or liquefied natural gas to that market. While the project was "speculative at this time", it was still under consideration.

Estimates for 1965-69 supplied by British Columbia Hydro and Power Authority ("B.C. Hydro") and by Inland were adopted by Westcoast. For the period 1970-85, its own estimates, based on population trends, expected number of

customers, and past experience, were used to forecast residential and commercial requirements. Industrial requirements, both firm and interruptible, were based on experience and on consultations with distributors. Since the 1964 hearing, B.C. Hydro's estimated gas requirements for power generation had been increased for the years 1965 to 1968 and its estimate of sales of interruptible gas had been substantially reduced.

Westcoast had not asked either B.C. Hydro or Inland for their forecasts of gas requirements beyond the fifth year, nor did it relate total British Columbia gas requirements to the availability of alternative sources of energy, e.g. power from the Columbia and Peace River projects. Westcoast pointed out that since B.C. Hydro is the exclusive distributor of electricity and gas in the Lower Mainland of British Columbia its policies would determine their relative use.

#### Canadian Requirements - Conclusions

The Board considered the estimates of long-term Canadian requirements provided by Alberta and Southern and Trans-Canada, and the estimates for British Columbia markets adduced by Westcoast. The Board has incorporated in Appendix 2 its own estimates of natural gas demand in Canada.

In its estimates of Canadian requirements, the Board took into account such factors as future population, number of households, relative use of principal heating sources, including electricity, in the residential and commercial sectors

in major consuming areas within provinces, price relationships between the various sources of energy, and capital cost of conversions. In the industrial sector, the Board evaluated potential growth in each major marketing area, relying mainly on end-use analyses of major consuming industries and on the competitive conditions between natural gas and other sources of energy.

For the years to 1985 end-use studies were made. Beyond that year, the Board extrapolated trends.

Alberta and Southern, in estimating Canadian requirements, used the population forecast of the Royal Commission on Health Services. In addition to that projection, the Board had the benefit of forecasts which have been prepared for other federal departments and agencies. The absence of reference to any population forecasts in Trans-Canada's application was noted.

In estimating saturation levels for the consumption of various fuels, the Board examined data on household formation trends, concluding that the number of persons per household would decline slightly over the forecast period. Alberta and Southern, however, deemed the number of persons per household to be constant.

Neither of the Applicants examined the effect of electric space heating on natural gas saturation levels.

To the extent that electricity captures any of this market, their forecasts may be overstated. The Board concurred with the Applicants on the question of area extension and envisaged little penetration beyond the areas now served by natural gas. The Board considers, particularly in areas where natural gas has only a marginal cost advantage over other energy sources, that the major impetus to residential gas usage will come from construction of new dwelling units, rather than from conversion of established dwellings.

In forecasting commercial sales of natural gas, the Applicants' evidence showed constant ratios between residential and commercial sales. While the Board found this to be true for Alberta and Saskatchewan, in Quebec, Ontario, Manitoba and British Columbia, commercial gas sales have not yet reached a stabilized level in relation to residential sales.

The Board's assessment of the residential and commercial sectors was substantially in agreement with those of the Applicants.

As to industrial sales, the limited historical data for provinces where natural gas has been made available only recently makes forecasting somewhat difficult. The Board has studied the characteristics of market potential and load factor to assess the probable growth in this sector.

The Board agrees with Trans-Canada that in Quebec, following a period of readjustment, resumption of growth in industrial sales can be expected.

In Ontario, the rate of increase in industrial gas sales is, in the Board's view, expected to exceed for some time that of the overall rate of growth in energy use. However, the recent high rate of growth in gas use will probably not be maintained. The period up to 1970 is expected to be one of rapid growth but at a declining rate of increase. This view closely parallels that of Trans-Canada.

No major disagreements in the estimates for Manitoba were registered. In Saskatchewan, the Board's estimates correspond with those of Alberta and Southern. Through its own study of the Alberta market, the Board confirmed the findings of the Alberta Board as published in its report OGCB 11-64. The "other industrial" category listed by the Alberta Board has been included.

In British Columbia, the industrial energy consumption is anticipated to rise by about 4 per cent annually up to 1985, by which time the Board estimates that gas will supply 33 per cent of the total energy consumption. The Board's sales estimate approximates Westcoast's projection.

In comparison with the Applicants' estimates for provinces served by Western Canadian sources, the Board

forecasts for natural gas vary mainly in the components of the demand rather than in the total requirements.

Both Applicants, Alberta and Southern and Trans-Canada, provided forecasts by provinces of maximum daily requirements. Alberta and Southern prepared its estimates in terms of the daily maximum market demand whereas Trans-Canada's forecast was in terms of demands on its system for provinces east of Saskatchewan.

In the Board's calculations of Canadian peak day requirements, severe rather than average winter conditions were postulated. Historic peak day requirements and weather data of low temperature extremes, daily expected averages, and frequency of occurrence at specific weather stations were governing factors. Allowances were made for differences in degree-days within provinces. However, in the overall total, the Board assumed that the market peaks would occur simultaneously throughout the country.

The co-operation of the Director and Staff of the Air Services, Meteorological Branch, Department of Transport, Toronto, in providing specific information and guidance, is gratefully acknowledged.

The Board has examined the evidence and concludes that, based on 1,000 Btu thermal content per cubic foot,

the aggregate Canadian requirements for gas in the period 1965-94 will approximate:

East of the Province of Alberta	25,825 Bcf
Province of Alberta	10,566 Bcf
Province of British Columbia	<u>4,080</u> Bcf
Total Canadian Requirements*	<u>40,471</u> Bcf

The peak day market demand, i.e. before allowing for peak shaving facilities, storage and other related factors, will rise throughout the period considered, reaching in 1994 approximately the following:

East of the Province of Alberta	6,532 MMcf/d
Province of Alberta	2,580 MMcf/d
Province of British Columbia	<u>1,046</u> MMcf/d
Total Canadian Maximum Day Market Requirements (Coincidental Peak)*	<u>10,158</u> MMcf/d

\*Including fuel and pipe line losses involved in the delivery.

#### Reserves - Evidence

All of the Board's reserves calculations, excluding trend gas, are on the basis of "established reserves", which the Board defined in its March 1960 report as: "reserves which can be considered established in the sense that their existence and estimated amounts can reasonably be counted upon". Established reserves have been calculated by crediting 100 per cent of proven reserves plus a varying percentage, not

exceeding 50, of probable reserves. Probable reserves were estimated where there was not sufficient well control to justify proven status, by taking into consideration known geology, previous experience with similar types of reservoirs, and seismic data if available. Probable reserves have not been allocated to pools considered to be fully developed and have only been credited to one-well discoveries under geological conditions which indicate a strong likelihood of additional reserves being developed.

The reserves estimates submitted by the Applicants and Intervenors covered both proven and probable categories. These were defined in a manner generally consistent with the use of these terms by the Board.

Alberta and Southern and Trans-Canada presented detailed estimates of reserves for those fields in which they have reserves under contract. Westcoast and the Province of British Columbia presented detailed estimates for British Columbia fields. These estimates of Alberta and Southern, Trans-Canada and Westcoast are discussed in sections 5, 7 and 8 of this report.

In estimating overall provincial totals of reserves, both Alberta and Southern and Trans-Canada adopted the reserves estimates for Alberta contained in the Alberta Board report. Also, both companies accepted the reserve values of the National Energy Board for British Columbia as contained in

the Board's report to the Governor in Council of July 1964. Estimates of reserves for Saskatchewan, in the case of both Applicants, were taken from the report of the Petroleum and Natural Gas Branch of the Department of Mineral Resources of that Province as of 31 December 1963. With respect to other areas of Canada, both Alberta and Southern and Trans-Canada relied upon the reserve estimates compiled by the CPA as of 31 December 1963.

On the foregoing basis, Alberta and Southern and Trans-Canada estimated established reserves as of 30 June 1964 to be 41.5 Tcf and 41.4 Tcf respectively. The Applicant, Canadian-Montana, adopted all estimates of reserves made and presented by Alberta and Southern.

In its intervention, Westcoast estimated the "total established pipe line gas reserves" in British Columbia to be 6.4 Tcf as of 31 December 1964. During the hearing, Westcoast introduced additional reserves evidence which increased its estimate to 6.5 Tcf.

The intervention of the Province of British Columbia listed the "established reserves of natural gas", as compiled by the Department of Mines and Petroleum Resources of that Province, at 6.6 Tcf. This estimate was based on detailed work on the part of the Department itself augmented by three reports prepared by consultants on behalf of the British Columbia Energy Board.

The firm of DeGolyer and MacNaughton studied all available geological and engineering data of "certain gas fields and areas in extreme Northeastern British Columbia". In addition, the firm reviewed the reserves in Westcoast's submission and concluded that its estimate of proven reserves was reasonable. DeGolyer and MacNaughton considered, however, that established reserves were approximately 10 per cent higher than estimated by Westcoast.

The study of McDaniel Consultants (1965) Limited, was confined to an analysis of trends in natural gas discoveries in "the northern portion of the Northeastern part of British Columbia and the adjacent areas in the Yukon and Northwest Territories". In order to make this assessment, the firm adopted the reserves estimate prepared by Westcoast.

J.C. Sproule and Associates Ltd. prepared estimates of proven and probable gas reserves "in the general Fort Nelson area, within that part of Northeastern British Columbia north of latitude 57° 30' and extended to the immediate area of the Celibeta gas field in the Northwest Territories". Certain specific fields were eliminated from this consideration "on the grounds of presently unfavourable economics". Total reserves listed by the firm for six reservoirs in the area and 20 single wells totalled 1.9 Tcf proven and 0.7 Tcf probable.

The Province of British Columbia also filed the Report of the British Columbia Energy Board of March 1965 in which that Board concluded that the reserves of the Province were a minimum of 6.7 Tcf and a maximum of 6.9 Tcf, presumably as of 31 December 1964.

The intervention of the Province of Alberta adopted the reserves for Alberta contained in the Alberta Board report. That report, on page A-34, lists the total "established reserves" for Alberta as 35.7 Tcf as of 30 June 1964, equivalent to 35.5 Tcf at 14.73 psia.

BA listed the "established reserves" in Western Canada at 45.5 Tcf as of 31 December 1964. This estimate includes the proven reserves and all of the probable reserves.

The CPA submission estimated 45.6 Tcf of "established remaining reserves of marketable gas" for all Canada as of 31 December 1964, equivalent to 45.3 Tcf at a pressure base of 14.73 psia. This estimate included all of the proven reserves, plus probable reserves which the Association "considered ... to be conservative".

Evidence was also presented concerning the amount of established reserves, presently considered to be beyond economic reach. Both Alberta and Southern and Trans-Canada adopted the assessment of reserves beyond economic reach for Alberta, 3.4 Tcf, as reported by the Alberta Board in November 1964. With respect to British Columbia, both

Applicants adopted the estimates of reserves beyond economic reach contained in the National Energy Board report of July 1964.

In arriving at its estimate of "total present reserves in Alberta within economic reach and available in thirty years", Westcoast subtracted all reserves considered by the Alberta Board to be beyond economic reach. Westcoast used this value in determining that there existed a reserve deficiency in the Province of Alberta. On the other hand, Westcoast's assessment of reserves in British Columbia made no provision for reserves beyond economic reach since in its view all reserves "will surely be connected within twenty years".

In addition to the estimates of established reserves received at the hearing, the Board has had the benefit of the technical advice of its own staff concerning fields located in Alberta and British Columbia.

#### Reserves - Conclusions

Having considered all the evidence relating to reserves and the advice of its staff, the Board has set the established reserves for Canada at 41.8 Tcf as of 31 December 1964. A comparison of the estimates submitted by the Applicants with those adopted by the Board is shown in the following tabulation.

## Established Reserves - Tcf\*

14.73 psia and 60°F

	Date of Estimate	Alberta	B.C.	Sask.	Other Canadian	Total
A&S	30 June/64	35.5	4.8	0.9	0.3	41.5
TCPL	**	35.5	4.8	0.9	0.2	41.4
Westcoast	31 Dec./64	-	6.4	-	-	-
B.C. Dept. of Mines	31 Dec./64	-	6.6	-	-	-
B.C. Energy Board	31 Dec./64	-	6.7-6.9	-	-	-
BA	31 Dec./64	-	-	-	-	45.5
CPA	31 Dec./64	36.3	7.9	0.9	0.2	45.3
Alberta	30 June/64	35.5	-	-	-	-
NEB	31 Dec./64	35.4	5.3	0.9	0.2	41.8

\*Where necessary the estimates have been converted to the common base.

\*\*No date given, assumed to be 30 June/64.

In considering the matter of reserves beyond economic reach, the Board had the benefit of the opinions expressed at the hearing, as well as the advice of its own staff. It concludes that of the Canadian established

reserves of 41.8 Tcf, 3.8 Tcf are now beyond economic reach; of this total 3.4 Tcf are located in Alberta and 0.4 Tcf in British Columbia.

#### Trends - Evidence

In its report to the Governor in Council of March 1960, the Board pointed out that there are two methods generally used to forecast the development of oil and gas reserves; the geological method and the statistical method. These methods were explained in some detail in that report. In summary, it may be stated that the geological method is related to the volume of sediments in any given area, and the expected amounts of oil and/or gas reserves to be found in each unit volume of those sediments, in order to predict the ultimate reserves. This approach requires reference to experience in other sedimentary basins which have attained a much more mature status. The method provides a relatively rough estimate of ultimate reserves which estimate is subject to amendment as knowledge of the sedimentary basin increases. It does not take account of the time or amount of drilling that would be required to determine the ultimate reserves. On the other hand, the statistical method employs cumulative data related to exploratory drilling, discoveries, and appreciation of reserves under established trends which can be used to predict the future growth rate of reserves.

The Board received evidence bearing upon both methods during the hearing. Evidence based on the statistical method covered both long-term and short-term periods.

Alberta and Southern did not calculate ultimate reserves in Canada by the geological method, but presented analyses of the historical trends in gas reserves growth in Alberta as these related to exploratory wells drilled, and the increase in reserves for exploratory wells drilled west of the 5th meridian as compared with the provincial average. These analyses supported Alberta and Southern's prediction, using the statistical method, that for the next 10 or 15 years Canadian reserves of initial marketable gas would grow at the rate of 3.4 Tcf per annum. This growth rate was derived by extrapolation of the rate of the annual reserves increase of 2.5 Tcf for the last 12 years, as determined by the Alberta Board in 1964, and by adding to this figure 0.8 Tcf for British Columbia, being the average annual reserves increase as estimated by the National Energy Board in 1964, and 0.1 Tcf estimated as the combined growth rate for Saskatchewan, Manitoba, Eastern Canada, and the Northwest Territories. Alberta and Southern concluded that "there is no practical reason to consider that the historical rates of increase in initial gas reserves experienced since the early fifties will not be maintained or even exceeded during the forecast period if there is also a continuation of market incentive. Therefore, it appears entirely reasonable to

extend a projection of reserve growth ... for a period of at least ten years".

Canadian-Montana adopted all data and evidence regarding trends in the growth of reserves submitted by Alberta and Southern.

Trans-Canada submitted that, based on the geological method, the ultimate reserves to be discovered in Manitoba, Saskatchewan, Alberta and Northeast British Columbia would be approximately 240 Tcf. This estimate did not include the Yukon, Northwest Territories, Hudson Bay Lowlands or the Continental Shelf areas lying off the Atlantic and Pacific coasts although these areas were considered prospective. In this estimate the Western Canadian Provinces were compared with the "Mid-Continent"\*\* area of the United States, which area was considered to have similar geological conditions and history, but which had reached a "mature stage of exploration and development" relative to the Canadian area. Trans-Canada considered this estimate of ultimate reserves in Canada to be reasonable since it assumed no further increases in reserves per unit volume of sediments for the Mid-Continent area. The Applicant estimated that approximately 47 Tcf of reserves had been discovered in Western Canada as a result of exploration drilling density of 95 feet per cubic mile of sediment. Exploration density in the Mid-Continent area is approximately eleven times that of Western Canada. The Applicant's studies

\*defined to be all of the States of Kansas, Oklahoma and Texas

indicated that the Mid-Continent area had experienced no apparent decline in the finding rate until an exploration drilling density, approximately three times the present density for Western Canada, had been reached. Even then, 50 to 60 per cent of the reserves discovered to date have been discovered during the period of decline in the finding rate.

Trans-Canada concluded that the annual trend of additions to reserves in Western Canada during the past 10 years averaged 3 Tcf per year. Having regard to the ultimate reserves expected for Western Canada in comparison with the history of the Mid-Continent area, the Applicant concluded that the average trend rate of 3 Tcf per annum, could be maintained over the next 30 years "providing that the market incentive justifies the necessary exploratory drilling". However, Trans-Canada believed that a reasonable estimate of the ultimate potential provided a sounder basis for predicting the availability of gas to protect future demand.

BA stated that it supported the estimate of 300 Tcf for ultimate gas reserves in Western Canada as prepared by the CPA.

Using the statistical method, BA presented evidence that "proven and proven-plus-probable" reserves found in Western Canada averaged 0.57 MMcf and 0.74 MMcf per foot of exploratory drilling respectively, during the period 1958 to

1962 inclusive. This assessment was based on crediting appreciation of reserves to the year of discovery, rather than to the year in which such appreciation occurred. BA did not believe that the 1963 and 1964 discoveries have been sufficiently appreciated as a result of development drilling to be included in the analysis. The company concluded that over the period in question there was no apparent decline in the amount of reserves found per foot of exploratory drilling. BA also stated that the rate of exploratory drilling in Western Canada, in recent years, had been 4.0 to 4.5 million feet annually. It stated that "with favourable market incentives, we are confident that this level of activity (exploratory drilling) will be maintained or increased in the future". Based on this assumption and the results of exploratory drilling since 1958, BA concluded that "gas reserves in Western Canada will increase by an annual average of some 3 Tcf, due to new discoveries". It did not state the period of years over which it believed this conclusion to be valid. BA did state however, that "appreciation of established reserves will provide up to 5 Tcf of additional gas reserves in the future", assuming no further exploratory drilling.

The CPA stated that its Geological Committee had re-assessed its "estimate of the possible reserves within the Canadian Sedimentary Basin" and it concluded that the

CPA submission made to the Royal Commission on Energy in 1958 was still valid both in respect of the total reserves and in respect of the reserves for Alberta. The Association submitted that total ultimate reserves in Western Canada were 300 Tcf and that the corresponding figure for Alberta was 150 Tcf.

The Association also concluded from its examination of statistical data, that over the period 1954 to 1964, the increase in proved plus probable recoverable gas reserves had averaged 3.6 Tcf annually for Western Canada. This rate was equivalent to 3.3 Tcf of marketable gas reserves. Corresponding figures for the proved category only were estimated to be 3.1 and 2.8 Tcf per annum respectively.

The Westcoast submission quoted the CPA submission to the Royal Commission on Energy to the effect that the ultimate gas reserves of British Columbia were forecast to be 75 Tcf based on the geological method.

Westcoast presented statistics on reserve growth in British Columbia indicating that proven reserves had increased over the period 1961 to 1964 at the average annual rate of 706 Bcf as a result of new discoveries and the appreciation of reserves discovered in previous years. Looking ahead 10 years, the company concluded that its present estimate of "initial disposable proved pipe line gas reserves" would appreciate by 2.2 Tcf by 31 December 1974. New discoveries throughout

the period would amount to 5.1 Tcf for a total value of 14.0 Tcf of initial disposable proved pipe line gas reserves by 31 December 1974. The future discovery component of this estimate was based on an anticipated drilling rate of 65 wildcat wells per annum and an average addition to reserves of 10.8 Bcf per wildcat well when fully appreciated over a 10-year period.

Westcoast further estimated that initial disposable gas reserves in British Columbia would amount to 27.5 Tcf and 47.0 Tcf when the drilling density had attained one wildcat well per 20 square miles and one wildcat well per 10 square miles, respectively. Based on the assumption of 65 wildcat wells per year, the exploration density corresponding to the former estimate was predicted for the year 1994 and the latter estimate (47.0 Tcf) was considered to be the ultimate reserve value for the Province.

The term "wildcat well" as used by Westcoast is assumed by the Board to be similar to the term "exploratory well" as used by the Alberta Board. The Board has adopted the term "exploratory well" for this report.

The Province of British Columbia in its intervention presented some findings regarding trends in gas discovery in that Province. J.C. Sproule and Associates Limited estimated that the ultimate recoverable reserves in Northeastern British Columbia would total 90 Tcf. This estimate was subdivided

into 20 Tcf for the northern area (north of 57 degrees, 30 minutes latitude), 30 Tcf for the southern area and 40 Tcf for the foothills and mountains. That firm also estimated "that industry could expand its capacity sufficient to develop reserves in Northeastern British Columbia at a rate of about 1.5 Tcf per year over the next twenty-five years. If that were done, it would result in the discovery of 37.5 Tcf of gas by 1990". This conclusion was based on the assumption that "sufficient incentive" be given.

McDaniel Consultants (1965) Ltd. concluded that a total ultimate reserve of 23.9 Tcf could be forecast for the northern portion of Northeastern British Columbia and the adjacent areas in the Yukon and Northwest Territories. That firm further concluded that on the basis of drilling 25 purely exploratory wells per year that area would achieve additional gas reserves in the order of 550 Bcf annually.

The Province of Alberta commended the Alberta Board report to the attention of this Board. That report concluded that for Alberta the "average growth in initial marketable reserves of gas due to new discoveries and to appreciation of previous discoveries has been at a long term rate of 2.5 trillion cubic feet per year". It also concluded that initial marketable reserves now established would appreciate by 3.4 trillion cubic feet.

Although the Alberta Board in its report pointed out that fully appreciated reserves developed per exploratory well have, on a cumulative basis, declined from over 8 Bcf in 1954 to about 7 Bcf in 1964, it believed that, in the matter of ultimate reserves for the Province, its previous estimate in the range of 60 to 80 Tcf appeared to be low. Accordingly, it increased its estimate of ultimate reserves to approximately 100 Tcf, which it considered reasonable and which it had tested by an extrapolation of the long-term trend of reserves per exploratory well to the ultimate number of wells expected to be drilled.

#### Trends - Conclusions

The National Energy Board has considered the evidence regarding ultimate reserves in Western Canada which was presented at the hearing and it has also had the advice of its own staff in this matter. While the comparison of the Western Canadian sedimentary basin with the Mid-Continent area of the United States is considered useful in its broad aspects, the occurrences of the thick Triassic-Pennsylvanian sediments in the Mid-Continent area do not have their counterparts in the Western Canadian basin. Moreover, significant parts of the Canadian basin do not present an opportunity for multiple reservoir conditions to occur one on top of the other to the same extent as they do in the United States. Neverthe-

less, the Board feels that the estimate of 240 Tcf prepared by Trans-Canada and the estimate of 300 Tcf prepared by the CPA can be considered as indicative of the upper limits likely to be realized.

Plots of the initial reserves against cumulative exploratory wells have been prepared for Alberta and British Columbia, as shown on Figures 1 and 2 of Appendix 3. These plots are based on the reserves set by the Board as of 31 December 1964, and indicate the cumulative initial reserves by years, as estimated by the Board effective 31 December 1964, and the corresponding cumulative exploratory wells drilled. In addition, because reserves during recent years have not reached full appreciation, appreciation factors obtained from the Alberta Board report and Westcoast's intervention have been used to plot the fully appreciated reserves curve shown for Alberta and British Columbia, respectively. Best-fit curves have been drawn through these historical data and extrapolated to 20,000 cumulative exploratory wells in Alberta and 5,100 cumulative exploratory wells in British Columbia. These totals were chosen on the basis of representing one well per 10 square miles of sediments and are

considered to be approximately the ultimate density of exploratory drilling for each Province. The ultimate reserves corresponding to this drilling density are 96 Tcf in Alberta and 38.5 in British Columbia.

Data in the Alberta Board report indicate that, on an average, 410 exploratory wells have been drilled annually in Alberta over the last 12 years. The Board believes that this average rate can be maintained during the next 20 years provided the incentives for exploratory drilling are maintained at levels comparable to those experienced during the past decade. By 1984, cumulative exploratory wells in Alberta should number approximately 15,000. Figure 1 indicates that initial reserves at that time on a fully appreciated basis would amount to 78.0 Tcf, being an increase of 35.7 Tcf from the current level. Accordingly, the Board believes that trends in growth of reserves in Alberta are likely to average 1.8 Tcf annually over the next 20 years.

The recent annual rate of exploratory drilling in British Columbia, according to the evidence of Westcoast has been about 60 wells per year. With a continuation of incentives, the Board believes this rate can be maintained and that by 1984 cumulative exploratory drilling in that Province should number 1,760 wells. Figure 2 indicates that initial

reserves on the fully appreciated basis would amount to 18.0 Tcf at that time, or an increase of 10.4 Tcf from the current level. Accordingly, the Board believes that trends in the growth of reserves in British Columbia are likely to average 0.5 Tcf annually over the next 20-year period.

The Board concurs with the estimated growth rate of 0.1 Tcf per annum for other areas of Canada as suggested by the Applicants. The Board considers this growth rate to be a lower limit, bearing in mind the anticipated exploration, for instance in the Yukon and the Northwest Territories, which will likely occur during the next 20 years.

In summary, the Board estimates the rate of growth in Canada will average 2.4 Tcf per annum for the next 20 years. In making this estimate, the Board recognizes that the growth rate for individual years may fluctuate widely from the average. In general, it expects that the rate will decline with time but that growth will continue well beyond the 20-year period.

Figure 3 in Appendix 3 shows the estimated growth in initial established reserves (fully appreciated) for the Provinces of British Columbia and Alberta, as well as the Canadian total, for the next 30 years. This figure is based on the assumption that exploratory activity will continue throughout the period at the average rates mentioned above.

The Board's report of March 1960 presented a forecast of initial established reserves in Alberta, British Columbia

and total Canada over a 30-year period (Figure 1 of that report). This forecast indicated that these reserves would amount to 46.6 Tcf by 31 December 1964, after addition of cumulative production to 31 December 1959. The Board's present estimate of initial established reserves, as of 31 December 1964, is 48.1 Tcf, indicating that actual performance has been 1.5 Tcf higher than expected over the four-year period.

#### Surplus - Evidence

The Board received evidence concerning the extent to which Canadian reserves are surplus to present and anticipated Canadian requirements plus existing export commitments plus the volumes applied for. Evidence was also given concerning the manner in which surplus should be determined. The following matters were discussed in varying detail:

- (a) the treatment of gas presently considered to be beyond economic reach,
- (b) the treatment of gas deferred for reasons of conservation,
- (c) the treatment of future reserves based on trends in the growth of reserves,
- (d) the number of years for which requirements of individual provinces and Canada as a whole should be protected from established and future reserves.

Alberta and Southern advanced the theory that foreseeable Canadian requirements would be adequately protected

if there were reserved out of presently "contractable reserves"\*\* an amount equal to 25 times the annual gas use in Canada for the third year in the future (defined as "presently contractable requirements of natural gas in Canada"), with the proviso that the current trends in discovery should demonstrate that annual increases in gas reserves would be greater than the predicted annual increases in contractable requirements in Canada over a future period in which forecasting could be reasonably accurate, suggested to be in the 10 to 15-year range.

Alberta and Southern estimated contractable reserves to be 40.7 Tcf as of 1 July 1964. This was arrived at after deducting 5.9 Tcf for reserves beyond economic reach or production of which would be deferred for conservation purposes, and adding 2.3 Tcf, being 50 per cent of the appreciation calculated for contractable supply fields in Alberta plus an adjustment of 0.8 Tcf in British Columbia reserves to reflect changes in reserve estimates published by Westcoast during 1964.

Alberta and Southern estimated "presently contractable requirements in Canada" to be 17.7 Tcf ( $25 \times 706 \text{ Bcf}$  - its estimate of Canadian use in 1967). By deducting this amount and a further 7.6 Tcf for remaining commitments under present export licences, Alberta and Southern calculated the surplus of Canadian gas to be 15.4 Tcf as of 1 July 1964. In making

\*defined as reserves which a pipe line buying organization would, in arm's length negotiation with the producers, recognize as the supply available for take-or-pay purchase commitments

this calculation of surplus, Alberta and Southern made no provision for reserves to cover terminal-year peaks for either Canadian requirements or export commitments. Presumably these would be provided from future discoveries and appreciation of known reserves.

The Applicant presented a table indicating that the surplus of "net contractable gas reserves" at the end of each calendar year would grow from 16.4 Tcf in 1964 to 30.9 Tcf in 1974 and to 37.3 Tcf in 1979, assuming the following:

- (1) an anticipated growth rate of 3.4 Tcf per year of initial marketable reserves;
- (2) Canadian requirements at 25 times the forecast for the third year following the year for which the surplus was calculated;
- (3) annual exports at a rate including amounts already authorized under existing licences and amounts currently applied for by Alberta and Southern and Canadian-Montana under licence applications now before the Board.

Canadian-Montana adopted all of the evidence presented by Alberta and Southern with respect to surplus.

Trans-Canada used an approach somewhat similar to that of Alberta and Southern in estimating the surplus of contractable reserves as of 1 July 1964 but adopted the formula used by the Board in its 1960 report to determine the reserves

necessary to meet the long-term Canadian requirements and export commitments.

After deducting 6.3 Tcf for reserves beyond economic reach or production of which would be deferred for conservation purposes, contractable reserves as of 1 July 1964 were estimated by Trans-Canada to be 35.2 Tcf. This is 5.5 Tcf lower than the Alberta and Southern estimate. The difference is mainly because Trans-Canada did not adjust its Alberta reserve estimates for heating value (Alberta and Southern reserves were adjusted to a 1,000 Btu basis) and it made no allowance for appreciation of presently contractable reserves.

In calculating the contractable reserves required to meet foreseeable Canadian requirements, Trans-Canada multiplied its 1968 estimate of Canadian requirements, excluding Alberta, by 24 and added 6.2 Tcf as its estimate for Alberta (5.2 Tcf is now under contract to Alberta utilities and Trans-Canada estimated that these utilities may purchase an additional 1.0 Tcf by 1968), making a total of 18.8 Tcf as compared with 17.7 Tcf estimated by Alberta and Southern. Trans-Canada stated that it used this method because it is common to contract for gas on a basis whereby, if gas is taken at minimum rates, the reserves dedicated to the contract are equivalent to approximately 27 years' supply and, if gas is taken at maximum rates, the reserves are equivalent to approximately 20 years' supply. It believed a 24 years' supply,

which would result from an average purchase rate approximately midway between minimum and maximum rates, to be reasonable at this time.

Special treatment was afforded to Alberta because of load factor problems.

Trans-Canada also estimated the reserves required to protect present export commitments at 9.9 Tcf, being 24 times the permitted annual rate in 1968. The balance of authorized exports as of 1 July 1964 was estimated to be 7.6 Bcf, the figure used by Alberta and Southern in determining its available surplus, but Trans-Canada contended that the amount of gas actually contracted for to support the production of the 7.6 Tcf would be in the order of 9.9 Tcf.

Using the aforementioned assumptions, Trans-Canada estimated the surplus of contractable reserves as of 1 July 1964 to be 6.5 Tcf, some 9 Tcf less than the estimate of Alberta and Southern.

Trans-Canada presented a tabulation indicating that 71.6 Tcf of reserves would be needed to protect Canadian requirements on a 30-year basis plus (a) presently authorized export volumes, (b) the amount of gas it is now seeking authority to export, and (c) potential exports of 0.1 Tcf to Vermont and New York States. Provision was included in the calculation for meeting Canadian peak-day requirements in the 30th year but no provision was made for terminal-year protection for export licences on the grounds that "all present export licences would have expired by that time".

Using established reserves of 41.5 Tcf as of 1 July 1964, it followed that 30.1 Tcf of additional reserves would have to be found in the next 30 years, approximately 1 Tcf per year. Comparing this figure with its trend evidence that a finding rate of 3 Tcf per year "can be reasonably maintained with adequate market incentive", Trans-Canada was confident there would be no problem in finding the necessary reserves.

Westcoast did not submit evidence concerning the overall Canadian surplus. It did, however, present two tabulations, the first dealing with the availability of British Columbia gas plus Peace River (Alberta) gas, to meet British Columbia requirements, present export commitments, and the requirement of PG&E, over a 21-year period, for the annual volumes that Alberta and Southern is applying to export from Alberta. The second tabulation covered the availability of Alberta reserves to meet Canadian foreseeable requirements for Alberta and eastward and present export commitments, including the licence applications currently being considered (for which Alberta has issued permits).

In its analysis for British Columbia, it adopted the method used by this Board in its March 1960 report, in determining requirements to be supplied from established reserves. The existing export commitment to El Paso was included to the extent of its annual requirements to the termination date of the export licence in 1977. No peak-day protection of that commitment was provided.

Based on this analysis and comparison with its own reserves estimate, Westcoast concluded that its supply sources had a surplus of 3.7 Tcf before consideration of its proposed export to PG&E and 1.4 Tcf after such consideration.

In its analysis for Alberta, Westcoast also used the Board's method for determining requirements other than those for Alberta to be provided from established reserves. Westcoast included the full 30-year requirements for Alberta as determined by the Alberta Board - a much greater degree of protection than that used by the National Energy Board in 1960. The analysis indicated a deficiency of 8.7 Tcf. In cross-examination it was elicited that while Alberta's full 30-year requirement of 16.1 Tcf was included in the calculation, no consideration was given to the fact that, in the Alberta Board report, this was partially covered by 5 Tcf of trend gas and by 1.8 Tcf of the 3.5 Tcf now considered beyond economic reach, but which the Alberta Board was confident would become within economic reach within the 30-year period. Westcoast, in its analysis of British Columbia reserves, considered all its reserves to be within economic reach.

It was also brought out in respect of Westcoast's analysis of Alberta reserves that 2.8 Tcf of gas was included in the reserve requirements to meet terminal peak-day deliverability of export licences which expired prior to the end of the period under consideration, while a similar provision for Westcoast's export to El Paso was not included in the analysis for British Columbia.

Concerning the degree of protection for Canadian requirements, the CPA stated in its submission that it "recognizes that there are practical reasons for protecting domestic gas markets by regulatory control of exports. However, the Association believes that a considerable measure of protection is already provided by the present circumstances of the gas supply industry. In this connection it is submitted that areas presently served by gas are well protected by the customary long-term gas purchase contracts. For future markets, supplies will be readily obtainable from future discoveries. In this respect it is noted that the average discovery rate established over several years is at least three times the current demand."

A witness for the Association, when asked to enlarge upon the position of the Association with respect to the use of future reserves from trends in meeting Canadian requirements, referred to evidence given last year before the Alberta Board. At that time, it was recommended that consideration be given to adding 5 to 10 years of trend gas to established reserves when determining the Province's surplus.

BA stated its view that "a realistic appraisal of surplus reserves must include consideration of reserve growth trends". The company did not, however, suggest the extent of such consideration.

The submission of the Province of Alberta contained the following paragraph bearing upon the degree of protection for Canadian consumers:

"The policy of the Province of Alberta is to protect its future requirements for a period of 30 years and while it believes this appropriate in the case of Alberta where the bulk of the gas reserves is owned by the people of the province, protection for such a long period clearly is not appropriate for Canada as a whole."

The Honourable E.C. Manning, Premier of the Province of Alberta, presented evidence on behalf of that Province and pointed out that in Alberta natural gas occupies a "position unique and rather different" from other areas of Canada. "We feel as a government that this not only justifies, but almost necessitates, us ensuring to the Province of Alberta ... supplies adequate for a longer period than would be the case were it not for the fact that gas occupies this unique position (in Alberta)." In this connection, it should be noted that while Alberta protects its own requirements for 30 years from "total available reserves" there is included in this figure 5.0 Tcf, being the estimated growth in reserves over a two-year period. Questioned regarding the degree of protection that he would suggest this Board apply to Canada as a whole, Mr. Manning stated: "I believe it is 21 years that has been a sort of general yardstick

that has been used. We have felt that that was reasonable for Canada."

The Honourable Robert Bonner, the Attorney General of British Columbia, giving evidence on behalf of that Province, quoted as follows from the report of the British Columbia Energy Board on the subject of protection for British Columbia gas requirements:

"Reserve requirements calculations have been made by use of the National Energy Board approved formula

... In accordance with the procedure adopted by the National Energy Board, reserve estimates for existing contracts were levelled off at third year (1968) requirements. Incremental requirements beyond the third year level are allocated to future discoveries of gas."

Asked for his views regarding the degree of protection which this Board should apply to Canada as a whole, Mr. Bonner said "I would think in the light of the probable Canadian reserves, about which there is a good deal of speculation, that our 20-year rule ... it is, I think 10 years under (less than) the Alberta rule ... would be very satisfactory for the nation as a whole. For the Province (British Columbia), I am quite sure that we would not go below the 20-year rule which I indicated we were using informally to this time and the likelihood is if there were change, it would be upward more to conform to the Alberta experience and practice."

Surplus - Conclusions

In discussing the question of surplus, Alberta and Southern made the following statement in its application: "For most mineral resources the simple demonstration that present contractable supply is greater than present contractable requirements by industry standards would suffice. If reasons should also exist for confidence in continued reserve growth the situation would be classified as most satisfactory. However, in the natural gas industry in Canada it is recognized that there has evolved a special concern for the evaluation of future trends. There is a concept of assuming a present responsibility to partially guarantee the long-term supply of this particular fuel to present and future consumers who are considered to be exclusively dependent upon (a) gas as a fuel and (b) on conventional natural gas supply sources originating within the Dominion."

The Board finds itself in general agreement with this Applicant's statement although perhaps holding a somewhat different view with respect to the origin of the concern for the future status of surplus. The Board is well aware of the hazards of long-term forecasting and the lack of accuracy usually present in the later years of such forecasts. However, the Board believes that both the available reserves and the requirements which must be supplied by such reserves must be forecast in order to give some assurance that supplies will not be deficient during the period of protection.

In its report to the Governor in Council of March 1960, the Board, for purposes of estimating Canadian gas requirements to be supplied from established reserves, included all of the Alberta requirements as these would grow throughout the period to 31 December 1980 and, for the balance of Canada, took the requirements as they would grow for the first four years and levelled them at that rate for the balance of the period. With respect to future surplus, the Board considered future reserves as these were anticipated to grow during 30 years and compared this value with the anticipated growth of all Canadian requirements throughout the 30-year period.

In the case of the determination of both current and future surplus, the Board gave full annual and terminal peak-day protection to the licences already issued as well as those being sought at that time. No account was taken of the fact that reserves necessary to protect the terminal peaks of the licences would be available for meeting Canadian requirements beyond the expiry dates of the licences.

The Board has reviewed the treatment which it gave to the consideration of surplus in its 1960 report and finds its basic approach to be still sound. It notes that the Alberta Board in its consideration of Alberta surplus in its 1964 report, developed the term "reserves available". This was a reserve number which had been adjusted from established

reserves by taking into account reserves beyond economic reach, reserves deferred for conservation reasons and two years of trend gas (future reserves). The Board believes the term "reserves available" is useful in determining current surplus. As outlined in the following discussion the Board believes its previous method should be modified with respect to:

- (a) use of reserves beyond economic reach,
- (b) accounting for reserves deferred for conservation reasons,
- (c) release of reserves allocated to terminal peak-day protection of licences as these expire,
- (d) inclusion of short-term growth of Alberta reserves to offset the longer term of protection afforded Alberta requirements.

(a) The Board has considered the approach of the Alberta Board, wherein it concluded that 50 per cent of the reserves presently deemed beyond economic reach will likely remain beyond reach during the period for which Alberta consumers are being protected. This Board agrees with that assessment and believes that the same criteria can be applied to British Columbia reserves. Accordingly, it assumes that 50 per cent of Alberta and British Columbia reserves presently beyond economic reach will be available for meeting Canadian requirements and export commitments.

(b) Further, the Board believes that reserves not expected to be available for reasons of conservation during the period of protection should be deducted from established figures. The Board accepts the estimate of the Alberta Board concerning such reserves in that Province. For British Columbia, the Board believes that the amount of gas which will not be produced during the protection period for reasons of conservation is so small that it may safely be ignored.

(c) The Board believes it to be proper to credit to the surplus account, reserves which had been allocated for the protection of peak-day requirements in the terminal year of an export commitment and which would become available for other use after the termination of the licence. This procedure was adopted by both Trans-Canada and Westcoast.

(d) During recent years, it has become the practice of the Alberta Board, in determining reserves available, to make an allowance for reserves which it anticipates will be established as a result of long-term trends in the appreciation of known reserves as well as the discovery of new reserves. In its report of November 1964, the Alberta Board allowed 5.0 Tcf, equivalent to 2 years of such trends, in arriving at total reserves available. In its analysis of Canadian surplus the Board believes it proper that, in protecting Alberta requirements to the degree to which they are protected by the Alberta Board, recognition should be given to 2 years future growth in Alberta reserves. Accordingly, for the purpose of determining

current surplus, the net Alberta requirements to be met from "reserves available" have been taken as the full 30-year requirements less 5 Tcf (2 years reserve growth).

The Board in its report to the Governor in Council of 1960 discussed in some detail the method of determining the amount of gas reserves which would be needed to supply Canadian requirements plus export commitments. It was pointed out that reserves necessary to protect requirements for a specific period fell into two portions: the actual volumes of gas to be delivered during that period and the amount of gas required to ensure delivery of the peak-day requirements in the terminal year of the period. Both annual and peak-day requirements have been estimated by the Board and a discussion of these estimates is presented earlier in this section.

The amounts of gas reserves necessary to meet the foregoing requirements were calculated in 1960 by use of the following formula:

$$R_n = K \left( \sum_1^n A + CFP_n \right)$$

where,

$R_n$  = Total reserves of gas of a marketable quality needed for future requirements during a period of  $n$  years, Bcf.

$K$  = Reservoir recovery factor, i.e. ratio of recoverable gas to gas in the reservoir both of marketable quality.

$\sum_1^n A$  = The cumulative annual requirements for  $n$  years, Bcf.

n = The number of future years to be considered.

C = Correction factor by which the results of the formula method are equated to the results of detailed deliverability schedules.

F = Reserve delivery ratio, i.e. ratio of reserves of gas in the reservoir (corrected to equivalent marketable gas volumes) to their attributable deliverability, Bcf per MMcf/d.

P<sub>n</sub> = The peak-day requirement in the nth year, in MMcf.

This formula, adaptable to any selected period of requirements and desired degree of protection for those requirements, permitted the grouping of fields for the determination of reserves necessary for annual and peak-day deliveries. In this manner, the time-consuming process of individual deliverability calculations on a field by field basis was eliminated. In 1960 the Board assumed a constant C factor value of 1.3 in all cases, based on a study made by the Alberta Board at that time. Since the completion of the 1960 report the Board staff has developed a computer program which permits the determination of a corrected F factor (CF) used in the formula method. Using the computer program the Board staff has re-evaluated the factors used in the formula method for all fields in Alberta and British Columbia except those dedicated to the protection of Alberta requirements. The Board staff does not have the reservoir data for these fields and

has accepted the formula factors apparent from the Alberta Board's report of November 1964.

Individual deliverability studies were not made by the Board's staff for Saskatchewan and Ontario fields. These fields were assumed to have, on the average, characteristics similar to those Alberta fields supplying Trans-Canada. In view of the relatively small reserves for these Provinces, moderate departures from this assumption would have slight effect on the end results.

The following tabulation permits comparison of the formula factors as presently determined with those used by the Board in its 1960 report.

<u>Market</u>	<u>Formula Factors</u>			
	<u>CF</u>		<u>K</u>	
	<u>1960</u>	<u>1965</u>	<u>1960</u>	<u>1965</u>
Trans-Canada	3.1	3.8	0.86	0.85
Alberta and Southern	2.6	4.3	0.90	0.84
Canadian-Montana (Cardston)	2.6	4.3	0.90	0.84
Westcoast	3.9	3.0	0.85	0.87
Westcoast (Kingsgate)	3.6	5.6	0.88	0.85

Changes in the factors between the two dates are a result of the addition of new fields which have been discovered and contracted for, as well as the more complete analysis performed by the computer.

Using the formula method with the new factors, the Board has ascertained the amounts of established reserves which it considers to be necessary to meet Canadian natural gas requirements, including protection of terminal peaks, as set forth in Tables 1 and 2 of Appendix 2 and Table 3 of Appendix 3, plus the commitments under existing export licences. These determinations are set forth and summarized in Table 4 of Appendix 3. Explanatory notes follow each table, setting forth the sources of information and the calculation procedures used for each. Table 5 of Appendix 3 sets out the Board's estimates of the amounts of gas required to supply the present applications including protection of terminal year peaks.

The following tabulation summarizes the Board's findings as to reserves available as of 1 January 1965, the volume of reserves needed to supply current requirements, including those associated with the present export applications, and the derived surplus position.

Current Surplus

(All volumes in Tcf at 1,000 Btu's per cubic foot)  
 (Table, column and line references are to Appendix 3)

Reserves Available

Established reserves*	
within economic reach	39.7
Plus one half of reserves beyond economic reach	2.0
Less reserves deferred	<u>0.5</u>
Total	41.2

\*Alberta and British Columbia reserves  
 were converted from 14.73 psia and  
 60°F to the 1,000 Btu's per cubic foot  
 basis using the average heating values  
 apparent from the Alberta Board report  
 and Westcoast's intervention

Reserves Needed to Meet Current Requirements and ApplicationsCanadian Markets (Table 4, Column 10)

British Columbia (net), Line 1	2.2
East Kootenay, Line 3	0.1
Alberta, Line 5	11.4
Canada, East of Alberta (net) Line 6	<u>10.9</u>
	24.6

Existing Export Commitments (Table 4,  
Column 3)

Canadian-Montana GL-8, Line 8	0.2
Westcoast (Sumas) Line 9	1.3
Alberta & Southern GL-3, Line 10	3.6
Canadian-Montana GL-5, Line 11	0.3
Niagara Gas GL-6, Line 12	0.1
Trans-Canada GL-1, Line 13	1.1
Westcoast GL-4, Line 14	<u>1.0</u>
	7.6

Present Export Applications (Table 5,  
Column 11)

Alberta & Southern, Line 1*	2.3
Canadian-Montana, Line 2*	0.2
Trans-Canada, Line 3	<u>2.1</u>

\*Adjusted. See pages 5-15 and 6-5

4.6

Total

36.8

Surplus

4.4

Accordingly, the Board concludes that there would be a surplus of natural gas in Canada in the amount of 4.4 Tcf, after providing for forecast Canadian demand, existing export commitments and the volumes of exports which are the subject of this report. Of this surplus, the Board estimates that 2.2 Tcf would be in British Columbia and the Peace River area of Alberta, after taking into account the present requirements of markets served from these areas, the other 2.2 Tcf being in Alberta (excluding the Peace River area).

The Board holds that in order to recommend additional exports it is necessary not only to prove the existence of a current surplus but also to show with reasonable certainty that the surplus will continue in the future.

Using the same formula factors as previously noted, the Board has prepared an estimate of the reserves necessary to meet Canadian requirements over a 30-year period, including the provision of protection for peak-day requirements in the thirtieth year, all remaining volumes under existing export commitments and all volumes under the present applications. These estimates are set forth in Tables 4 and 5 of Appendix 3 along with supporting notes which explain the assumptions and methods of calculation.

The following tabulation summarizes the Board's estimates of the reserves available as of 1 January 1965 and the growth in reserves for the next 20 years; the volumes of

gas necessary to supply Canadian requirements for the next 30 years, existing export licences, and those now under consideration; and the derived surplus position.

### Future Surplus

(All volumes in Tcf at 1,000 Btu's per cubic foot)  
 (Table, column and line references are to Appendix 3)

#### Reserves

Reserves available	41.2
Trends 2.4 Tcf/year x 20 years	<u>48.0</u>
Total	89.2

#### Reserves Needed to Meet Future Requirements and Applications

##### Canadian Markets (Table 4, Column 9)

British Columbia (net) Line 2	6.1
East Kootenay, Line 4	0.3
Alberta, Line 5	16.4
Canada, East of Alberta (net), Line 7	<u>35.9</u>
	58.7

##### Existing Export Commitments (Table 4, Column 3)

Canadian-Montana GL-8, Line 8	0.2
Westcoast (Sumas), Line 9	1.3
Alberta & Southern GL-3, Line 10	3.6
Canadian-Montana GL-5, Line 11	0.3
Niagara Gas GL-6, Line 12	0.1
Trans-Canada GL-1, Line 13	1.1
Westcoast GL-4, Line 14	<u>1.0</u>
	7.6

##### Present Export Applications (Table 5, Column 4)

Alberta & Southern, Line 1*	1.7
Canadian-Montana, Line 2*	0.1
Trans-Canada, Line 3	<u>1.7</u>

\*Adjusted. See pages 5-15 and 6-5 3.5

Total

69.8

Surplus

19.4

Accordingly, the Board concludes that the presently available reserves plus the growth in reserves over a 20-year period will be sufficient to provide for the full protection of Canadian requirements over a 30-year period including protection of the terminal peak, existing export commitments and the export volumes herein considered. Although the Board expects that Canadian reserves will continue to grow well beyond the 20-year period, confining the estimates of growth to that length of time indicates that the above requirements will be served and a surplus of some 19 Tcf will be developed.



## APPLICATIONS OF ALBERTA AND SOUTHERN AND ALBERTA NATURAL

Evidence in Regard to Application

Markets - The proposed export volumes are destined for the California market served by PG&E.

Letters of intent dated 21 May 1964, between Alberta and Southern and PGT on the one hand, and PGT and PG&E on the other, were filed in support of the application. These letters are subject to receipt of necessary governmental authorizations.

Supply - Alberta and Southern presented evidence for 68 individual reservoirs. The Applicant estimated that its contracts and option agreements in these reservoirs provided 6.8 Tcf of initial marketable reserves, of which 6.1 Tcf were proved reserves and 0.7 Tcf were probable reserves. The company expressed the view that it was sufficiently confident of its estimates of probable reserves that application of a further discount factor was not required. Cumulative production to 31 October 1964 was estimated by the company at 0.4 Tcf. Subtraction of this production from the company's estimate of initial reserves yields a total remaining reserve value of 6.4 Tcf as of that date.

The Board has completed a review of each of the gas reservoirs under contract or option agreement to Alberta and Southern and estimates that Alberta and Southern had 6.7 Tcf

of established reserves under its control as of 31 December 1964.

Alberta and Southern filed illustrative deliverability schedules to demonstrate the ability of its proven and probable reserves to meet the annual and peak-day volumes authorized under Licence GL-3 issued to Alberta and Southern and Licence GL-5 issued to Canadian-Montana, plus the additional deliveries until 31 October 1989 proposed by the Applicants. The maximum annual and peak-day volumes applied for increase after 31 October 1986 by volumes corresponding to those authorized under Licences GL-3 and GL-5 which expire on that date. Hence, one effect of the present applications, if granted, might be said to be to extend the 25-year life of Licences GL-3 and GL-5 by three years.

Using its deliverability computer program, the Board's staff has prepared illustrative deliverability schedules on a basis comparable with those of the Applicant. However, the staff's schedules were based on the established reserves of Alberta and Southern's fields as set by the Board. On instructions of the Board, for reasons discussed later in this section, the annual and peak-day volumes requested in the Alberta and Southern and Canadian-Montana applications were reduced by the proposed increases in volumes after 31 October 1986.

The following tabulation shows the annual and peak-day deficiencies as indicated in the illustrative deliverability schedules prepared by Alberta and Southern and the Board staff.

Deficiencies in Meeting Requirements  
from Reserves under Contract

(1,000 Btu's per cubic foot)

	<u>Alberta and Southern</u>		<u>National Energy Board</u>	
	<u>Annual Bcf</u>	<u>Peak MMcf/d</u>	<u>Annual Bcf</u>	<u>Peak MMcf/d</u>
1964-1979	-	-	-	-
1980	-	-	6	19
1981	-	-	16	50
1982	-	-	34	105
1983	-	-	46	141
1984	-	-	65	197
1985	-	-	77	234
1986	-	53	128	391
1987	18	111	-	-
1988	86	299	-	-
1989	<u>105</u>	<u>351</u>	<u>-</u>	<u>-</u>
Total	<u>209</u>		<u>372</u>	

The preceding tabulation of the Board's staff analysis indicates that Alberta and Southern can maintain the peak-day deliverability for 15 years from 1964 until 1979. The first deficiency occurs six years earlier than

shown by the analysis prepared by Alberta and Southern. The difference between the two analyses is assumed to be due primarily to the manner in which the production from individual fields was scheduled. The analysis prepared by the Board's staff, reflecting as it does a reduction in the proposed export volumes after 31 October 1986, indicates no shortage in deliverability for the three years following that date.

The total of annual deficiencies in the amount of 372 Bcf is 5.3 per cent of the Board's estimate of established reserves in fields under contract to Alberta and Southern as of 31 December 1964.

Estimates of the total reserves required by Alberta and Southern, including those required for peak-day protection, have been prepared by the Board's staff for the periods ending 31 October 1986 and 31 October 1989, by the formula method. The estimate for the first period, ending on the terminal date of Licences GL-3 and GL-5, shows a greater reserves requirement than the estimate for the second period due to the reserves needed for peak-day protection of these licences until 31 October 1986. The reserves required for the period ending on that date are indicated to be 7.6 Tcf on the basis of 1,000 Btu's per cubic foot. Comparison of this reserves requirement with the reserves available, as estimated by the Board and converted to 1,000 Btu's per cubic foot, indicates

that approximately 0.6 Tcf of additional reserves would be required by Alberta and Southern to assure peak-day deliverability to 31 October 1986. These additional reserves would also assure continuing deliveries until 31 October 1989 at the combined annual and peak-day rates of some 82 Bcf and 250 MMcf for Alberta and Southern and Canadian-Montana. No difficulty need be anticipated in the contracting for reserves by Alberta and Southern to meet the small apparent deficiency.

Facilities - The additional facilities for which a certificate is sought by Alberta Natural consist of a new compressor station, additions to an existing compressor station and additions to a meter station at the international boundary near Kingsgate, B.C., totalling in cost \$5,383,000. It is proposed to increase pipe line capacity in two stages over a two year period to accommodate the increased volumes of gas for which a licence is sought by Alberta and Southern. A map showing location of existing and proposed facilities is included as Appendix 4.

The Alberta Natural pipe line forms a link in the overall pipe line system between Alberta and California. When asked if corresponding increases in capacity would be provided by each of the connecting systems, namely, Trunk Line, PGT and PG&E, the Applicant stated that it was certain that additions to the PGT and PG&E systems would be constructed at the appropriate time. A letter from Trunk Line was also submitted stating that it is prepared to construct the additional

facilities needed in its system. The producers in Alberta would construct field gathering pipe lines and gas processing plants where necessary to meet the Applicant's construction schedule.

The Applicant proposes to install a gas turbine-driven centrifugal compressor in the new compressor station. This type of compressor had been selected because of its lower overall operating cost. While an additional 20 acres of land for the new compressor site would be required it was not anticipated that expropriation would be necessary.

According to the Applicant, the pipe line system between Alberta and California would be capable, at design winter conditions, of transporting from Kingsgate the estimated maximum day volumes, including Alberta gas purchased by El Paso from Westcoast, of 714 MMcf/d in 1966-67 and 830 MMcf/d commencing in 1967-68. Should a compressor unit at a critical location on its system fail to operate during peak demand, the flow rate would be reduced by 45 MMcf/d and 63 MMcf/d respectively, i.e., to approximately the average daily level. Under these circumstances, PG&E could make up for the loss in flow by using alternative methods, such as withdrawal of gas from storage or curtailment of interruptible loads.

The Applicant stated that it plans to purchase Canadian manufactured materials and to use Canadian based technical personnel and Canadian labour to the greatest extent possible.

In addition to seeking certification for the proposed additional facilities, Alberta Natural asked for certain amendments in wording of Certificate No. GC-12. These are not significant and are intended to bring that certificate into conformity with those currently issued by the Board.

Financial - Under a contract between Alberta and Southern and Trunk Line dated 14 June 1960, gas is transported on a cost of service basis from the points where it is delivered for account of Alberta and Southern to the points of connection with the Alberta Natural system and the Canadian-Montana system. Westcoast is also a party to the agreement and Trunk Line carries gas for it on the same basis for delivery into the Alberta Natural system. The cost of service for each shipper includes a proportionate share of operating expenses, depreciation, amortization and taxes. A return of 7 1/2 per cent on the net investment base, determined in accordance with a formula contained in the contract, is also included and provision is made for partial payment in United States dollars for service and redemption of securities payable in that currency. Certain minor modifications, previously covered by letters of agreement, were incorporated in the contract by an amendment dated 31 January 1961.

Transportation of Alberta and Southern gas through the facilities of Alberta Natural is covered by a contract, to which Westcoast is also a party, dated 20 September 1960.

Under this contract gas is carried for Alberta and Southern and Westcoast on a cost of service basis. Such cost of service is computed on a basis similar to that specified in Alberta and Southern's contract with Trunk Line, and is prorated between Alberta and Southern and Westcoast in accordance with their respective daily contract quantities. This agreement also was amended as of 31 January 1961 in regard to the method of settlement and in certain other minor respects. The main effect of the amendment was to bring the terms of the contract relating to partial payment in United States dollars into line with the Trunk Line contract. Pursuant to the requirements of the contract Alberta and Southern on 29 September 1964 notified Alberta Natural and Westcoast of its desire to increase the daily contract quantity, subject to receipt of the necessary governmental authorizations, by approximately the same amounts specified in the application.

All gas being exported by Alberta and Southern is sold to PGT under a contract dated 31 January 1961. This contract is similar to Alberta and Southern's contract with Alberta Natural, being on a cost of service basis computed in essentially the same manner. The cost of gas, however, is included in the cost of service and is based on the weighted average price of gas purchased during the month. An amendment effective 1 January 1962 modified the method of settlement in

a manner similar to that provided by the amendment to the contract with Alberta Natural. Approximately the same additional quantities as the Applicant now wishes to export are covered by a further amendment dated 21 May 1964.

The contract between PGT and PG&E dated 15 September 1961 provides for pipe line service on a cost of service basis, including the cost of gas, in accordance with a rate schedule filed with the United States Federal Power Commission pursuant to the requirements of the Natural Gas Act. PGT advised PG&E by letter dated 21 May 1964 of its intention to deliver the additional quantities on the same terms and conditions as in the existing contract, which is in due course to be superseded by an amended agreement. PG&E has concurred in the proposal.

Alberta and Southern's sales of gas to Canadian-Montana are covered by a contract dated 31 January 1961. The contract is similar to that with PGT and it was amended in the same manner as that contract as of 1 January 1962. It was further amended on 21 May 1964 to increase the sales volumes by the quantity for which Canadian-Montana is concurrently requesting a licence.

Under an agreement dated 9 August 1957 Alberta and Southern has undertaken to sell, on an annual basis, such volumes of gas as may be mutually agreed upon to Canadian Western Natural Gas Company Limited and Northwestern Utilities,

Limited. At least one year's notice must be given by the utilities of the volumes required and certain considerations, including the availability of gas from other sources of supply, must be taken into account. The price payable by the utilities is to equal the weighted average field price paid by Alberta and Southern plus an appropriate transmission charge, interpreted as "the average unit cost per Mcf on the assumption that the gas delivered ... at any point comes from the closest field under our (Alberta and Southern) control which results in the lowest transportation charge". Provision is also made in the agreement for the sale of additional quantities of gas to meet the peak demand on the utilities while maximum use is being made of their other sources of supply to the extent permitted by existing facilities. The price payable for such additional gas would be 1.3 times the weighted average field price, plus appropriate transmission charge, or, at the option of the utilities, and at a time mutually convenient to the parties, the return of 130 per cent of the gas taken.

Alberta and Southern also has contracts with two small distributors in the Province of Alberta, the price being at a flat rate subject to renegotiation after 1 July 1968, failing agreement on which the matter will be determined by the Public Utilities Board of Alberta.

Pro forma statements of revenues and expenses accompanying the application showed that the field purchase

cost of gas to Alberta and Southern would increase from an average of 18.16 cents per Mcf in the year 1965 to 18.83 cents in 1968, the first year in which the full amount of the additional volumes covered by the application would be delivered. Transportation and other costs were expected to decrease, however, from 7.50 cents per Mcf in 1965 to 6.41 cents per Mcf in 1968, and the net profit of the company would remain substantially constant. Little change might be expected in the average price at the international border of gas sold by Alberta and Southern to PGT, 25.96 cents per Mcf in 1965 and 25.52 cents per Mcf in 1968.

As testified during the hearing, the incremental cost of moving the additional quantities of gas for which a licence was being requested through the Alberta Natural pipeline would be approximately 1.25 cents per Mcf. Adding this to the cost of the gas, approximately 19.75 cents per Mcf, yielded an incremental cost of the gas at the international border of approximately 21 cents in 1968. This figure took into account the volumes of gas requested for the years 1987 through 1989, which, if granted, would be equivalent in effect to extending the term of the existing licence from 1986 to 1989.

These average and incremental border prices were stated to be not wholly comparable since the average costs represented partly Canadian and partly United States currency whereas the incremental cost was Canadian currency only.

With regard to the responsibility of the Board under Section 83 of the Act, to satisfy itself that the price charged by an applicant for gas to be exported is just and reasonable in relation to the public interest, it was Alberta and Southern's contention that the only points to be established were whether a fair price was being received at the well-head for the national resource and whether the transportation charges to the border were reasonable. Westcoast expressed the view that comparison of the price of the Canadian gas at San Francisco with the cost of gas from other competitive sources was a relevant factor for the Board's consideration. Alberta and Southern took exception to this suggestion on the grounds that rates in the State of California were a matter for the Public Utility Commission of that State and that they should not be inquired into by this Board. Evidence given during the hearing as to the cost in California of gas obtainable from other sources is contained in the section of this Report dealing with Westcoast's proposal that British Columbia gas should be exported to California.

In respect of Alberta Natural's financial position as related to its application, increased operating expenses, attributable to the additional facilities and greater throughput, would be compensated for by higher revenues from Alberta and Southern and the company's net income would remain relatively

constant. The cost of the proposed new facilities, \$5,383,000, would be met almost wholly from cash and disposal of short-term investments and from funds generated during the intervening period until the facilities are constructed. The small remaining requirements for funds would be provided by short-term bank accommodation.

#### Conclusions

The Board has carefully examined the evidence submitted by Alberta and Southern in regard to its application. It has also given due consideration to the submissions of all Intervenors.

The Board is satisfied that the California market can readily absorb the volumes of gas for which an export licence has been requested. Insofar as the Applicant is concerned, the sale of these volumes is covered by a contract with PGT which, in turn, has received from PG&E a firm commitment to purchase approximately the same volumes of gas.

The Board concludes that the present established reserves of gas in fields under contract and option agreement to Alberta and Southern amounting to 6.7 Tcf, or 7.0 Tcf on the basis of 1,000 Btu's per cubic foot, are sufficient to provide for peak-day requirements specified in the applications of Alberta and Southern and Canadian-Montana until 1979. If reserves in fields under contract are augmented in the amount

of some 0.6 Tcf, and if the annual and peak-day volumes applied for in the three years ending 1989 are reduced by the volumes corresponding to those authorized under licences GL-3 and GL-5, as the Board proposes to do, then annual and peak-day deliveries can be assured throughout the period ending 31 October 1989. The deficiency in presently contracted reserves is small and, for the purpose of assessing the adequacy of supply for the requirements of Alberta and Southern and Canadian-Montana, is not deemed to be significant.

There is no reason to doubt that, subject to relevant regulatory authorizations, facilities would be constructed as required on each portion of the interconnected system between the producers and the consumers, to ensure the transportation of the additional quantities of gas for which a licence is requested. The Board concludes that the additional facilities for which Alberta Natural requests a certificate will be required if an export licence is granted and that it could finance their cost.

Insofar as price is concerned Alberta and Southern would obtain the gas to be exported as a result of arm's-length bargaining with various producers in Alberta. The sale price at the international border consists of this basic cost of the gas to which are added Alberta and Southern's costs, with a return of 7 1/2 per cent, as well as all costs of transportation computed on a cost of service basis.

Giving due weight to the representations of Westcoast and the Province of British Columbia, the Board concludes that the manner in which the border price has been arrived at results, in this specific instance, in a price that may properly be considered as just and reasonable in relation to the public interest.

The Board considers that approval of Alberta and Southern's application would be in the public interest, except in regard to the requested annual and peak-day quantities for the three years commencing 1 November 1986.

The application calls for additional export volumes of 74.8 Bcf each year from 31 October 1987 until 31 October 1986. Thereafter until 31 October 1989 the additional export volumes would increase to 228.1 Bcf annually. Approval of the application in this form would thus produce a "balloon" effect in the quantities authorized in the years 1 November 1986 to 31 October 1989 and in effect extend the existing licence for a further three years.

The Board, as a matter of policy, does not believe it to be in the public interest to authorize long-term exports on a pattern whereby the volumes in the terminal years greatly exceed the average volumes over the entire period of the authorization. To do so would presumably require the Board to allocate reserves for the protection of terminal peak-day

deliveries, in accordance with its normal policy, which would be disproportionately large relative to the amounts actually to be exported. In the present instance, calculations using the Board's formula indicate that, on the basis of 1,000 Btu's per cubic foot, 2.6 Tcf of reserves would be required by Alberta and Southern for the protection of the terminal peak-day (1988-89) quantities for which a licence is requested in the application in its present form. On the other hand, only 0.9 Tcf of reserves would be required for the protection of the terminal peak day if the annual volumes authorized under existing export licence GL-3 are subtracted from the quantities set forth in the application for the period 1 November 1986 to 31 October 1989. The Board believes that the effective date of the licence should be the date of the proposed first additional export of gas in accordance with the amended contract between Alberta and Southern and PGT.

The Board is prepared to issue a new licence in accordance with the terms of Alberta and Southern's application with the following exceptions:

- (a) deliveries under the licence would commence on 1 November 1966 and the annual and peak-day volumes for the year 1 November 1966 to 31 October 1967 would be 37.4 Bcf and 113.1 MMcf/d respectively.

(b) for the three years commencing 1 November 1986 annual and peak-day volumes authorized under this licence would be at the same levels as in the immediately preceding years, rather than at the higher levels requested.

The Board has given consideration to each of the amendments to Licence GL-3 requested by Alberta and Southern and which are set forth in Appendix 1.

The Board believes that for the purpose of overcoming temporary operating problems, the Applicant should be permitted to exceed by 10 per cent the maximum daily quantity which otherwise may be exported. It is prepared to amend the licence accordingly.

The Board is not prepared to amend condition (3) of Licence GL-3 in the manner requested by the Applicant. It believes that any licence issued by the Board must provide that the Licencee comply with the valid terms and conditions of related permit or permits from provincial authorities existing at the time the licence is granted. If the permit or permits are amended or superseded by new permits, the Board upon application or upon its own motion may, with the approval of the Governor in Council, amend the licence accordingly. The Board is prepared to amend Licence GL-3 to provide that the Licencee shall comply with the valid terms and conditions of Permit No. 64-3 issued by the Alberta Board.

The Board is prepared to amend condition (4) of Licence GL-3 as requested by the Applicant.

Construction of the facilities proposed by Alberta Natural would, in the Board's view, be required by the present and future public convenience and necessity and the Board is accordingly prepared to issue a certificate.

The Board has considered the application of Alberta Natural to vary Certificate No. GC-12 as set forth in Appendix 1. With some modification in wording to conform with the Board's current practice, it is prepared to amend the certificate in the sense requested.

## APPLICATION OF CANADIAN-MONTANA

Evidence in Regard to Application

Markets - The gas to be exported by Canadian-Montana would be sold at the international boundary to its parent company, Montana Power, to provide an addition to its general gas supply for areas within Montana served by that company.

Market forecasts for Montana for the period 1965-80 were provided in the application. A contract amendment dated 25 May 1964 between Canadian-Montana and Montana Power confirming the sale of this gas, subject to requisite authorizations, was submitted with the application.

Gas production in that state has proven inadequate to supply growing requirements. Looking beyond the present application, Canadian-Montana indicated that Montana Power would continue to depend on Canada to supplement its supply of local gas.

Supply - All aspects of reserves, deliverability and surplus of Canadian-Montana's application were discussed under the "Supply" section of Alberta and Southern's application. In all these matters Canadian-Montana relied on the evidence, opinions and conclusions of Alberta and Southern.

Facilities - Canadian-Montana has two 16-inch pipe lines, one located in Southeastern Alberta and one located in Southwestern Alberta, each of which connects with the pipe

line system of Montana Power at the international boundary. This application is concerned only with the export of gas through Canadian-Montana's pipe line facilities in South-western Alberta. The additional quantities of gas to be exported would be obtained through the existing interconnection with Trunk Line and no additional facilities would be required by the Applicant for the transportation of the total volume which would be delivered to Montana Power.

Financial - At the present time Canadian-Montana buys gas from Alberta and Southern under a contract dated 31 January 1961, delivery being made at the point of interconnection between the Trunk Line facilities and those of Canadian-Montana. Gas is delivered to this point under the contract between Alberta and Southern, Westcoast and Trunk Line already referred to in connection with the Alberta and Southern application.

The contract between Canadian-Montana and Alberta and Southern is on a cost of service basis, the cost of the gas being included therein at the weighted average price of gas purchased by Alberta and Southern during the month. The terms of the contract were modified, effective 1 January 1962, in respect of partial payment in United States dollars. A further amendment dated 21 May 1964 covers the additional quantities of gas specified in the application.

Gas purchased by Canadian-Montana from Alberta and Southern is resold to Montana Power under a contract dated 9 November 1961. This contract calls for delivery of the gas on a cost of service basis, including the cost of the gas to Canadian-Montana, all operating and maintenance expenses incurred in connection with its receipt and delivery, as well as all fixed charges, depreciation and taxes and a 7 1/2 per cent return. Except insofar as price is concerned, the terms and conditions contained in Canadian-Montana's contract with Alberta and Southern have been adopted in the contract with Montana Power. The last mentioned contract was amended on 25 May 1964 so as to incorporate the additional quantities of gas specified in the application.

Because of a reduction in the unit cost of transportation before the gas purchased from Alberta and Southern enters the Canadian-Montana line, the average purchase price of such gas would decrease from 23.88 cents in 1965 to 23.64 cents in 1968. Although the overall cost of operation of the Canadian-Montana pipe line is not materially affected by transmission of the proposed additional volumes, on a unit basis transportation and other costs would decrease from 0.23 cents per Mcf in 1965 to 0.14 cents per Mcf in 1968. The net change in the unit price at the international border of gas sold to Montana

Power, including a return of 7 1/2 per cent on Canadian-Montana's net investment, would be a reduction from 24.24 cents per Mcf in 1965 to 23.85 cents per Mcf in 1968.

#### Conclusions

The Board has carefully examined the evidence submitted in regard to the application of Canadian-Montana and, in so doing, has taken into account the fact that the application was not opposed by any of the Intervenors. No additional facilities are required on the Applicant's system in order to transport the additional volumes of gas.

From the evidence submitted, the Board is satisfied that the growth of the market area, already served in part by Canadian gas, requires the additional volumes of gas for which an export licence has been requested. All such gas would be obtained from Alberta and Southern. As indicated in the section of the Report dealing with that company's application, the deficiency in reserves in Alberta and Southern's supply fields necessary to fully protect annual and peak-day requirements of Alberta and Southern and Canadian-Montana for the period ending 31 October 1989 is small. The Board concludes, therefore, that for the purpose of considering the application of Canadian-Montana, the gas supply is adequate.

For the reasons discussed in relation to the application of Alberta and Southern, the Board is not prepared to issue a licence in the form requested by the Applicant, wherein the additional volumes authorized for export in the last three years of the licence would exceed those in the earlier years.

The licence the Board is prepared to issue would:

- (a) authorize deliveries commencing on 1 November 1966 and for the year 1 November 1966 to 31 October 1967 authorize export of annual and peak-day volumes of 3.7 Bcf and 12.0 MMcf/d respectively,
- (b) authorize annual and peak-day volumes for the three years commencing 1 November 1966 at the same levels as in the immediately preceding years.

On the matter of border price the considerations already discussed in regard to Alberta and Southern's application appear to be equally valid in this particular instance. Accordingly the Board finds that the proposed price is just and reasonable in relation to the public interest.

The Board has considered the application of Canadian-Montana to amend Licence GL-5 as set forth in Appendix 1. It is prepared to amend the licence substantially as requested.



## APPLICATION OF TRANS-CANADA

Evidence in Regard to Application

Markets - The application is of a unique nature since no firm market requirement has been established for the quantities of gas for which an export licence is being sought. The licence sought, for 186 MMcf/d, is required to enable Trans-Canada to satisfy the balance of the option in its original contract with Midwestern which stems from a precedent agreement of August 1955. Counsel for Trans-Canada stated that the only effective offer under the option would be one made following receipt of a licence to export from Canada the gas being offered. By tendering 186 MMcf/d to Midwestern, Trans-Canada would have discharged its obligation, unless and until, in the event of the full amount not being accepted by Midwestern, Trans-Canada sold gas at a point on the international border between the eastern boundary of the Province of Alberta and the shore of Lake Superior to some other purchaser on terms more favourable than had been offered to Midwestern. In such event the matter would be reopened.

In a letter dated 10 November 1964, Midwestern indicated that had Trans-Canada been in an authorized position to tender, Midwestern would at that time have been prepared under certain conditions to elect to take an additional 25 MMcf/d commencing in 1965. Moreover, Midwestern might be in a position to increase this quantity to 50 MMcf/d

commencing in either 1965 or 1966. The company indicated that, following a survey of its requirements, it might wish to elect to take an even larger quantity.

The actual volumes to be exported to Midwestern would be established at the termination of the 90-day time limit, as specified in the option clause, following the formal tender. During the hearing, Trans-Canada testified that the letter dated 10 November 1964 still represented Midwestern's position.

Supply - Trans-Canada presented evidence regarding all fields from which it purchases gas. Total initial recoverable reserves for these fields, plus the reserves of fields committed to Trans-Canada by other holders of Alberta permits to remove gas from that province were estimated by the Applicant at 13.2 Tcf as of 31 December 1964. Of this amount, 12.6 Tcf were proven and 0.6 Tcf were probable reserves. The company did not discount probable reserves in arriving at its statement of total volume, but for deliverability purposes generally did adopt a 50 per cent discount factor. Cumulative production was estimated by the company to be 1.3 Tcf as of 31 October 1964. Subtraction of this production from the company's estimate of initial reserves leaves estimated total remaining reserves of 11.9 Tcf as of 31 October 1964.

The Board has completed a review of each of the gas reservoirs under contract or letter of intent to Trans-Canada, plus the fields committed to Trans-Canada and covered by Alberta and Saskatchewan permits to others. The Board concludes that Trans-Canada had 11.5 Tcf established reserves under its control as of 31 December 1964.

Trans-Canada also filed an illustrative deliverability schedule for each of the years ending 31 October from 1964 to 1989 inclusive. This schedule was predicated on the Applicant's estimate of proven reserves plus 50 per cent of probable reserves for each field under its Alberta permit TC 64-6, plus reserves available from fields under permits to others. This schedule showed requirements levelled at the 1968 figure, thus including the additional export volumes herein requested, but not reflecting the expiry of the existing licence GL-1 on 14 May 1981. Comparison of the total maximum day volumes of gas available with the total peak-day requirements upon the Applicant's system, including those which are the subject of this application, indicates that total deliverability would fall short of meeting annual and peak-day requirements in 1980 by 5 Bcf and 13 MMcf respectively. By 31 October 1985 the annual deficiencies would total 796 Bcf while the peak-day deficiency in that year would be 721 MMcf.

Using the deliverability computer program, the Board staff has prepared an illustrative deliverability schedule comparable to that of the Applicant for the period 1964 to 1985. The years to 1985 correspond to the period used by the Board to determine the volume of reserves which would be necessary to protect Canadian requirements from established reserves as of 31 December 1964. As in the case of Trans-Canada's deliverability schedule, these requirements were also levelled at the 1968 figure. The staff used the established reserves of Trans-Canada (11.5 Tcf) as set by the Board, and the Applicant's estimate of requirements as these would grow until 1968 and levelled thereafter.

The Applicant's estimate of requirements for its Canadian markets in 1968 was in close agreement with the estimate of the Board staff for requirements of markets east of Alberta, as shown in Appendix 2, Table 2, after making allowance for gas to be supplied to these markets from other sources. In the deliverability schedule prepared by the Board staff the total requirements of Trans-Canada's system were reduced after 14 May 1981 to reflect expiry of the existing export licence GL-1 at that date.

Deficiencies in meeting Trans-Canada's requirements from reserves under its control, as estimated by Trans-Canada and by the Board staff, are shown in the following tabulation for the period 1964 to 1985.

Illustrative Table of Deficiencies in Meeting Requirements from Reserves under Contract  
(1,000 Btu's per Cubic Foot)

<u>Years</u>	<u>Trans-Canada</u>		<u>National Energy Board</u>	
	<u>Annual Bcf</u>	<u>Peak MMcf/d</u>	<u>Annual Bcf</u>	<u>Peak MMcf/d</u>
1964-78	-	-	-	-
1979	-	-	4	11
1980	5	13	30	87
1981	47	135	7	21
1982	106	305	30	86
1983	172	494	71	204
1984	214	613	131	375
1985	<u>252</u>	721	<u>174</u>	498
Total	<u>796</u>		<u>447</u>	

While the staff analysis indicates deficiencies commencing in 1979, these would, for the succeeding few years, be small in relation to Trans-Canada's system requirements. The Board considers that, having regard to the accuracy of this type of forecast, Trans-Canada's reserves would be sufficient to meet some 17 years of Trans-Canada's annual and peak-day requirements, including

those of the present application. The staff schedule indicates a total deficiency of 447 Bcf by the end of 1985 with a peak-day deficiency in that year of 498 MMcf. Taking into account the requested export volumes from 1986 to 1990, the balance of the term requested, the Board estimates that the sum of the deficiencies would be in the order of 790 Bcf.

Facilities - The Applicant made it clear in its application and by evidence at the hearing that it was not applying at this time for a certificate for construction of pipe line facilities. Evidence was presented, however, as to the extent and the estimated capital costs of such facilities as might be required for the proposed export to Midwestern. If the sales to Midwestern were 25 MMcf/d Trans-Canada stated that it would be necessary, in order to handle this volume plus the normal growth in Canadian requirements, to construct in the western section of its pipe line system an additional 59 miles of 34-inch diameter pipe line during 1965 at an approximate cost of \$9,000,000. In the event that Midwestern accepted an additional 50 MMcf/d, 82 miles of 34-inch diameter loop would have to be constructed at an approximate capital cost of \$12,300,000. In neither case would additional compression be required.

All but 18 miles of the pipe line between Burstall and Winnipeg would have to be looped in order to transport 186 MMcf/d to Midwestern and gas for the normal growth in Canadian requirements. If Trans-Canada finds it necessary to apply for facilities to export the full 186 MMcf/d, then in all probability it would apply at the same time to complete the 18 miles of looping in order to improve the reliability of its system as a whole.

Financial - A draft of the contract which Trans-Canada would propose to offer to Midwestern, pursuant to the terms of the option contained in the existing contract, was included in Trans-Canada's application. With the exception of price provisions and the option referred to, this draft is similar in all essentials to the existing contract.

Under the draft contract gas would be sold at prices in accordance with the following table (all prices expressed in United States currency):

<u>Period</u>	<u>Demand Charge \$/Mcf/Mo.</u>	<u>Commodity Charge ¢/Mcf</u>	<u>Average Price</u>	
			<u>15.025 psia ¢/Mcf</u>	<u>Converted to 14.73 psia ¢/Mcf</u>
First 5 years	2.47	19.71	30.538	29.938
Second 5 years	2.76	20.14	32.240	31.607
Third 5 years	3.05	20.52	33.891	33.225
Fourth 5 years	3.34	20.95	35.593	34.894
Fifth 5 years	3.63	21.38	37.294	36.561

The effect of the provisions regarding billing places the contract on a 75 per cent monthly load factor basis. This contrasts with the existing contract which for the first three years was effectively on a 75 per cent monthly load factor basis but is now a 95 per cent annual load factor contract.

Conversion of the proposed export prices to Canadian dollars at the rate of 92.5 cents United States equal to \$1.00 Canadian showed an escalation in average price per Mcf from 32.36 cents in the first five years to 39.52 cents in the fifth period of five years. The 25-year average would be 35.94 cents. The average price contained in the General Service Rate Schedule for Trans-Canada's Manitoba Zone at the same load factor is 32.15 cents per Mcf with no provision for escalation in later years. The prices to be paid by Midwestern would therefore be higher than those which a Manitoba distributor would be required to pay for similar service.

The application contained statements showing that, if the proposed contract covered the full amount of 186 MMcf/d and Midwestern took gas at an anticipated load factor of approximately 84 per cent, the average cost of transmission of all gas between Burstell and Winnipeg per Mcf per 100 miles would, as a result, be reduced from 0.95 cents to 0.89 cents. Although during the course of the hearings

certain amendments were made to the estimates of the facilities required, these changes were not considered by Trans-Canada to have any material effect on the estimated reduction in transmission costs.

At the request of the Board, Trans-Canada filed a statement after the hearing showing its computation of the cost of transmission between Burstall and Winnipeg if, instead of exports to Midwestern of 186 MMcf/d, only 25 MMcf/d or 50 MMcf/d were exported. This calculation showed costs of transmission per Mcf per 100 miles of 0.91 cents and 0.90 cents respectively.

#### Conclusions

The Board has carefully examined the evidence submitted in connection with Trans-Canada's application and, in so doing, has taken into account the fact that the application was not opposed by any of the Intervenors.

As previously indicated, the application is of an unusual nature in that no firm market requirement has been proved to exist for the quantities of gas which the Applicant seeks to export. The Board recognizes, however, that under the terms of the Midwestern option, the precedent agreement for which was entered into before the Board was established, the extent of the market cannot be determined until Trans-Canada offers gas in respect of which an export licence has actually been issued. As Midwestern would have

to advise Trans-Canada within 90 days of the volume of gas it elected to purchase, the volumes to be exported could be definitely established within a relatively short time after issuance of a licence.

Having regard to the history of the contract, the Board is prepared, in the particular circumstances of this case, to waive its normal requirements as to evidence of the existence of a market for the full amount of the export licence applied for. However, the Board desires to make clear that it is not its policy to entertain applications for "hunting licence" export authorizations, under which a firm purchase arrangement and a demonstrable market may - or may not - follow the issuance of a licence. The Board's normal practice will continue to be to require that purchase agreements and market data be established before an export licence application is set down for hearing.

With respect to supply, the Board's deliverability analysis indicates that the reserves of 11.5 Tcf estimated to be under contract to Trans-Canada can supply annual and peak-day requirements, including the additional export herein requested until 1982.

At the end of 1985 there would be a cumulative deficiency in meeting Trans-Canada's Canadian requirements

plus those of the present application of some 450 Bcf, with a peak-day deficiency of approximately 500 MMcf in that year. The annual deficiencies would total some 790 Bcf if provision is made for the annual volumes required during the balance of the term of the licence applied for. The Board is satisfied that the reserves required to meet the annual and peak-day deficiencies can be made available from the difference between the 14.1 Tcf of available reserves allocated by the Board to protect Canadian requirements east of Alberta, Trans-Canada's present export commitments and the volumes applied for, and the reserves of 11.5 Tcf controlled by Trans-Canada. The Board considers that the policy Trans-Canada has pursued to date in purchasing gas reserves has been satisfactory. Assuming this policy is continued, and having in mind the various facts previously set forth as to requirements and supply in the territories in which this company operates, the Board is confident that Trans-Canada can and will contract for the additional gas reserves necessary to offset the deficiencies now apparent.

Although no facilities application is before the Board in this regard, the manner in which Trans-Canada would install facilities on the western portion of its system to transport the volumes for which a licence is sought appears in general to be reasonable.

The price schedule which Trans-Canada and Midwestern propose for the additional sales of gas is the result of arm's length negotiation between the two companies. Although no contract for the sale of gas to a Manitoba distributor on a 75 per cent load factor basis at present exists, comparison of the proposed export prices with the corresponding Manitoba Zone Rate Schedule shows the latter to be consistently lower. Having regard to this and all other relevant information before it, the Board finds that the border price is just and reasonable in relation to the public interest.

The Board finds that approval of the proposed export in the amounts requested is in the public interest. It appears, however, that Midwestern may not take the full amounts authorized and therefore when those volumes of gas which Midwestern is prepared to accept have been precisely determined and the Board advised thereof, the Board will seek approval to amend the licence so as to reflect in the conditions the amounts of gas which Midwestern has agreed to take.

While Trans-Canada has applied for a licence for a period of 25 years extending to 31 October 1990, and the Board has satisfied itself that it would be consistent with

the public interest to issue a licence for that term, the Board is prohibited by Regulation 9(b) of the Regulations made pursuant to Part VI of the Act from issuing a licence for a period in excess of the period during which the removal of gas from the province of origin is authorized by that province. The relevant restriction is the terminal date of Alberta Permit No. TC 64-6, dated 1 December 1964, which is 31 October 1989. Under these circumstances, the Board is able, subject to the approval of the Governor in Council, to issue a licence to Trans-Canada only for a period of 24 years to 31 October 1989. A corresponding deduction of 68 Bcf would be made from the total quantity of gas to be exported, so that the total would be 1.632 Tcf rather than 1.700 Tcf.



INTERVENORS' SUBMISSIONS REGARDING TRANSMISSION  
OF BRITISH COLUMBIA GAS TO CALIFORNIA

Westcoast's Proposed Alternative to  
Alberta and Southern's Application

Westcoast asserted in its submission that, having regard to the Canadian interest, the Board should find that any export of gas to supply the markets described in Alberta and Southern's application should logically be drawn from the established reserves of gas in British Columbia which are now available to the Westcoast pipe line system.

A proposal had been made by Westcoast to Alberta and Southern, PGT and PG&E, that Westcoast should deliver at Sumas, Washington, for account of Alberta and Southern, the volumes of gas for which an export licence was now being sought. Such gas would be transported by El Paso through its northwest division from Sumas to Stanfield, a point of interconnection with PGT in the vicinity of Pendleton, Oregon. Thereafter the British Columbia gas would move to California in a blended stream with Alberta gas covered by Alberta and Southern's existing export licence. PG&E had rejected this proposal as uneconomic.

Westcoast stated that it recognized that under the Alberta and Southern proposal Alberta gas would be delivered at the United States border (Kingsgate) at a price much lower than British Columbia gas would be made available at Sumas. However, failure to realize the maximum benefit from its natural resources would be a loss to the Canadian economy.

Whether approval of the Alberta and Southern application would be in the public interest could only be judged in the light of the competitive price situation at Antioch, California, a distribution centre for the San Francisco area. In the normal course of business, if the gas available in British Columbia were competitive in California, a demand for such gas would develop. It was Westcoast's contention that the competitive situation in California was such that the market there could easily utilize gas from British Columbia at prices which would be acceptable to the United States purchaser, produce maximum amounts of United States dollars for Canada, encourage development of resources in more than one province, and give maximum protection to the Canadian consumer.

Westcoast admitted that it had no contract with any customer in California. On the contrary, in a letter dated 23 March 1965 PG&E had stated that if for any reason it was prevented from taking the gas which it had purchased in Alberta the alternative supply would be from the gas producing areas of the southwestern United States. The cost of gas from that source delivered in the San Francisco area was said to be much lower than the delivered cost of British Columbia gas in that area.

Westcoast stated that it was not asking for sole rights in the California market but merely for a share in it. The principal reason for its intervention was to test

whether it was in the national interest of Canada for large new volumes of gas to be exported at a low price and withdrawn from the area at present supplying all Canada east of the Rocky Mountains while at the same time similar volumes of gas in northern British Columbia, which were much more distant from these Canadian markets, were to remain shut in.

In summarizing the reasons for Westcoast's intervention, Counsel for Westcoast stated that the Board should consider carefully whether approval of the proposed export was in the general interest of Canada and, if so, whether some lesser term might not be more appropriate. In particular, the Board was requested to clearly state the gas policy for general use in Canada. This need not necessarily involve dedication of markets but should enable all the producing areas to share some measure of the available export markets.

Reference was also made to the non-resident nature of the whole operation of PG&E and its subsidiaries which, Westcoast's Counsel alleged, could mean that ascertained reserves were not in fact available for Canadian use. At the same time he suggested that not only were British Columbia reserves locked in but there was certainly no foreseeable future for the reserves in the Yukon or the Northwest Territories.

On the matter of price Counsel for Westcoast suggested that the Board should satisfy itself that gas was

not being dumped at distress prices. Although the field price was said to be an important factor to the producer, the real test was whether gas commanded a fair price in relation to other possible sources at its destination.

Westcoast contended that it had been Canadian Government policy as far back as 1953 to support exports of British Columbia gas to the United States Pacific Coast and this policy was said, on the strength of quotations from certain of the Board's reports, to have been consistently followed by the National Energy Board. Further, in the House of Commons on 1 April 1960 the Minister of Trade and Commerce had indicated that it would be a primary consideration of the Government in dealing with future applications for licences to export gas to the United States Pacific Coast whether such export would result in increasing use being made of Westcoast's pipe line and in promoting the development and use of exportable gas reserves in British Columbia.

Westcoast contended that the arrangement which it had proposed would provide the most effective means of implementing the economic development of the remaining potential gas resources of British Columbia. Further, the proposal was more in accord with the Canadian national interest, since it would lead also to development of areas of northwest Alberta, the Yukon and the Northwest Territories. Even though there might be more exploratory activity in British Columbia, the Yukon and northern Alberta than in

southern Alberta, Westcoast maintained that actual development would not take place until markets were available for the gas.

In order to develop a showing of ability to provide 207 MMcf/d of gas to replace that forming the subject of Alberta and Southern's application, Westcoast submitted a 20-year forecast of its total system requirements. This forecast provided for a continuance of exports to El Paso for Pacific Northwest markets until the end of 1977 at the minimum level specified under the existing contract. No provision was made for any exports to El Paso after 1977. Questioned as to the adequacy of this provision for the requirements of the Pacific Northwest area, Westcoast maintained that the forecast was not understated and that exclusion of any exports to El Paso after 1977 was justified on the basis that 1977 was the year in which the primary term of the contract expired and there was no assurance as to its renewal.

At the 1964 hearing in connection with Westcoast's application regarding the Fort Nelson extension the development of additional markets in the Pacific Northwest area had been forecast. Failure of these markets to materialize was attributed by Westcoast to the fact that its customer, El Paso, was in the process of divesting itself of the assets which it had acquired in 1957 from Pacific Northwest Pipe-

line Corporation. El Paso was, therefore, not in a position to negotiate for new gas supplies.

Under an agreement between Westcoast and El Paso (as successor to Pacific Northwest Pipeline Corporation) dated 11 December 1954 El Paso had an option to increase the contract demand provided in the contract. There was some difference of opinion as to whether this option had expired. In the view of Counsel for Westcoast the option was no longer in existence and accordingly no provision was made in the forecast for additional supplies of gas to El Paso.

On the general question of whether the Board could, or should take action which would have the effect of allocating markets to a particular production area, Westcoast stated that it believed in the principle of free competition but it also recognized that it had been deemed necessary in the national interest to establish some regulatory control of the natural gas industry.

Counsel for Alberta and Southern disagreed strongly with the position of Westcoast, contending that entry of the Board into the area of dedication of markets "would be disastrous to the gas industry, the producers and the Province of Alberta". It would also involve the Board in the fixing of well-head prices and raise various constitutional problems within Canada. It was also maintained that confidence in the Board, built up over a period of years, would suffer if

the Board attempted to force United States purchasers to pay a higher price than that at which Canadian gas might otherwise be available to them.

Eastern Canadian Markets - In Westcoast's submission it was stated that export of a disproportionate share of Alberta's gas resources to the California market would result in restriction of future supplies of gas at economic prices for Eastern Canadian markets. At the same time, it was submitted, the Pacific Coast area, including California, was the only available economic market for surplus British Columbia gas, since this gas was at present beyond the economic reach of the more easterly populated areas of Canada and the United States.

Alberta and Southern contended that Westcoast was not excluded from Eastern Canadian markets. On the basis of various hypothetical throughputs, studies had been made to establish the feasibility of building a pipe line from Westcoast's system to connect with the nearest points on the Trunk Line system at Edson or Kaybob, Alberta. These studies showed that gas from the Fort Nelson area could be delivered at the interconnection with the Trunk Line system at a cost of from 17.1 to 20.3 cents per Mcf, depending on the method chosen and the assumptions as to throughput. These prices were compared with average 1968 prices to be paid by the exporting companies for Alberta gas which,

after adjustment for currency exchange rate and heating value, would be in the range of 15 to 19 cents per Mcf. On this basis it was stated that the cost of British Columbia gas delivered in Alberta would be of a similar order of magnitude and indicated the existence of competitive opportunity.

Westcoast acknowledged that there might eventually be a market for it to the east of British Columbia but it stated that a pipe line to serve such a market did not at the present time seem feasible, since it would cross land containing gas which was already moving to the east. Studies undertaken by it indicated that gas sold at a well-head price of 10 cents per Mcf in the Fort Nelson area, would incur gathering, processing and transmission charges such that its cost, at the commencement of Trans-Canada's pipe line at Burstell, Saskatchewan, would be some 33 cents per Mcf or 37 cents per Mcf for movements of 400 MMcf/d or 200 MMcf/d respectively. This was compared to the present value of gas at that point of approximately 20 cents per Mcf.

Supply - Westcoast presented evidence on each of the individual reservoirs for which it has gas purchase contracts or option agreements. Evidence was also presented for other fields in British Columbia not at the present

time committed to Westcoast. Summary evidence only was given for the fields in Alberta which are allocated to Westcoast under Alberta Permit WC52-1, as amended. Westcoast estimated the total of all these reserves to be 7.4 Tcf, of which 0.9 Tcf are in Alberta. In the opinion of the company, all reserves were within economic reach.

The Board has completed a review of each of the gas reservoirs in British Columbia and those in Alberta assigned to Westcoast. The Board estimates that reserves in British Columbia, now available to Westcoast or which might become available to Westcoast amount to 4.9 Tcf. In addition, the Board estimates that reserves in Alberta now available to Westcoast amount to 0.3 Tcf. In arriving at the latter figure a major portion of the reserves of the Worsley field have been allocated to Alberta requirements in the same manner as done by the Alberta Board.

The evidence of Westcoast concerning deliverability was analyzed and a detailed deliverability schedule for the Westcoast system was prepared by the Board staff using its computer program. Using the appropriate formula factors derived from the program, a calculation was made of the reserves necessary to meet Westcoast's Canadian requirements, including terminal peak protection, plus the requirements of

the existing licence for export at Sumas. These requirements (Appendix 3, Table 4, line 1, column 9 and line 9, column 3) total 3.5 Tcf.

Westcoast now has within economic reach established reserves amounting to 5.2 Tcf. Adding 50 per cent of reserves beyond economic reach in British Columbia and the Peace River area of Alberta gives 5.6 Tcf, or 5.7 Tcf on a 1,000 Btu basis, as the total "reserves available" determined in a manner similar to that for Canada as a whole. Deducting from this total the requirements of 3.5 Tcf, the Board estimates that there is a current surplus of 2.2 Tcf.

Facilities - Evidence was given at the hearing by Westcoast of the additional facilities that would be required on its system to ensure delivery of the gas which it proposed to sell to Alberta and Southern in addition to providing for the normal growth in British Columbia markets. For the year 1966-67 Westcoast would require an addition to its Fort Nelson processing plant, additional compressor units at various locations on its system and partial looping of its transmission line, costing in all some \$15,800,000. For the year 1967-68 Westcoast would need further additions to its gathering system and to the Fort Nelson processing plant as well as additional compressor units and looping of transmission line, at a total cost of some \$53,578,000.

Westcoast stated that the system design of 739 MMcf/d in 1967-68 and 900 MMcf/d in 1968-69 was based on firm loads

plus certain interruptible loads "which it would not ordinarily order interrupted". It stated that, if a compressor unit became inoperative at the most critical location in the year 1968-69, after 24 hours during which use could be made of line pack, the system capacity would be reduced by 40 MMcf/d.

Evidence was given by Westcoast with respect to the facilities that would be required on the El Paso system to transport the proposed volumes of gas from Sumas to the interconnection with PGT facilities at Stanfield. El Paso currently sells, in the Pacific Northwest, gas which it receives from three sources:

From Westcoast at Sumas	303 MMcf/d
From Westcoast via Kingsgate and delivered by PGT at Spokane	150 MMcf/d
From United States fields, e.g. Big Piney in Wyoming, through its own system, approximately	<u>250 MMcf/d</u>
TOTAL - approximately	700 MMcf/d.

Westcoast indicated that the transportation of the additional volumes of gas it proposed to sell to Alberta and Southern would require expansion of El Paso pipe line facilities between Sumas and Stanfield — for the year 1966-67 additional compressors costing \$4,675,000 and for the year 1967-68 additional compressors and pipe line looping costing \$5,661,000. Westcoast made no provision in these estimates for the normal market growth in this portion of

the El Paso system and it had assumed that the El Paso facilities would meet only firm demands on a peak day.

Under the arrangements proposed by Westcoast, the additional gas delivered to El Paso at Sumas would displace equivalent volumes received into the El Paso northwest system from United States sources and a substantial portion of the gas delivered to PGT at Stanfield would be United States gas. The flow diagram for the maximum day delivery in 1968-69 indicated that 53 per cent of the 221 MMcf delivered would come from that source.

Cost of Transmission and Delivered Cost of Canadian Gas in California - In its submission Westcoast compared the cost of Alberta gas delivered at Antioch, California with the delivered cost of British Columbia gas transported through El Paso's northwest facilities to Stanfield and thence, through facilities of PGT and PG&E, to Antioch. According to these calculations in the year 1968, the first year in which the full 207 MMcf/d of additional gas would be exported, the delivered cost of Alberta gas at Antioch would be 40.13 cents per Mcf, whereas the corresponding figure for British Columbia gas would be 35.87 cents per Mcf. Westcoast admitted that in this comparison the costs assigned to the Alberta gas were those associated with the export of volumes covered by Alberta and Southern's existing export licence, whereas the costs of transmission assigned to

British Columbia gas for movement through the facilities of El Paso, PGT and PG&E were computed on an incremental basis. The statement was said to have been prepared, however, to demonstrate that British Columbia gas could be delivered at Antioch at a lower price than was at present being paid at that point for Alberta gas.

At the request of the Board, Westcoast during the hearing filed a further statement showing the respective costs of transporting Alberta gas alone and a mixture of Alberta and British Columbia gas to California. This statement made separate comparisons both on an incremental and on a "rolled-in" basis. The figures were computed by Westcoast partly on the basis of its own estimates and partly on the basis of a submission to the Federal Power Commission made by PGT in connection with its application to import into the United States the gas covered by Alberta and Southern's application to this Board. It was stated that El Paso figures had not been available and that the computations had been based on an estimate of the original cost of the pipe line which had been completed in 1956.

Rolled-in costs in the case of Alberta gas alone took into account all costs applicable to the gas being exported under the existing export licence and the additional quantities specified in the application. Provision was also made for the effect of continuing from 1986 to 1989 to export the quantities specified in the existing licence as proposed in the application. Rolled-in costs in the case of the

mixture of Alberta and British Columbia gas took account of all costs applicable to the Alberta gas currently being exported, the proposed border price of the British Columbia gas, a proportionate share of the costs of moving British Columbia gas through the El Paso system to Stanfield, and the additional costs involved in transporting this gas through the PGT and PG&E systems to Antioch.

This statement was later amended and the revised statement prepared along similar lines was filed after the hearing. Copies of this statement were forwarded to the other parties concerned and no objections to the figures have been received by the Board. The revised statement showed for the year 1968 the following:

	<u>Additional Gas from Alberta</u>	<u>Additional Gas from British Columbia</u>		
	<u>Incremental US¢ per Mcf</u>	<u>Rolled-in McF</u>	<u>Incremental US¢ per Mcf</u>	<u>Rolled-in McF</u>
Cost at International Border	19.63	23.83	29.00	27.15
Cost at Stanfield, Oregon	21.30	27.05	32.39	30.99
Cost at California-Oregon border	23.33	30.96	34.65	35.03
Cost at Antioch, California	24.58	34.75	36.06	38.81

In a letter which was read into the record by Westcoast, El Paso stated that, if required, it could transport gas in varying quantities up to 207 MMcf/d. The additional facilities required would depend on the quantities

involved but the statement of capital costs on which Westcoast had based its estimates of transportation cost through the El Paso system were not materially different from El Paso's own estimates of the capital costs that would have to be incurred. Transportation of the additional volumes would make greater use of the existing facilities thereby reducing the unit cost of transportation for the gas at present being moved. Actual transportation charges would have to be negotiated and these charges would be subject to the jurisdiction of the Federal Power Commission.

Comparison of Delivered Cost of Canadian Gas in California with Cost of Gas from Other Sources\* - In connection with Westcoast's contention that Alberta and Southern's gas was being sold at too low a price, both Westcoast and Alberta and Southern adduced considerable evidence. Much of the testimony related to the cost of gas purchased from El Paso at Topock, on the Arizona-California border, and transported through PG&E facilities to Milpitas. Milpitas, near San Francisco, is already connected to the El Paso system and was stated to be comparable to Antioch as a delivery point for the San Francisco Bay area.

In arriving at these costs it was necessary to make a number of assumptions and there was considerable disagreement between Westcoast and Alberta and Southern as to the propriety of some of the assumptions made by the other. In

\* Under this heading, references to gas prices are in terms of United States funds.

particular, questions were raised as to the extent and design of additional facilities which might be required by PG&E in the portion of its line between the Arizona-California border and Milpitas and the possibility of current proceedings before the Federal Power Commission resulting in gas price reductions. These differences of opinion were for the most part not resolved, but points on which there was some consensus are reflected in the following paragraphs.

It was generally agreed that if the additional volumes covered by Alberta and Southern's application were to be supplied by El Paso, the average cost of El Paso gas at Milpitas under the present rate schedule and transportation from Topock could be between 34 and 36 cents per Mcf. It was conceded that these figures might be reduced by several cents if certain other developments involving the El Paso system were to materialize. It was also agreed that the average cost of Alberta gas at Antioch, i.e. the "rolled-in" cost of present exports and the additional volumes applied for, would in 1968 be in the range of 34 to 35 cents per Mcf. These figures were compared with West-coast's estimate that the blending of Alberta and British Columbia gas, averaged in accordance with its proposal, would cost approximately 39 cents per Mcf at Antioch. No estimate of this cost was made by Alberta and Southern.

On an incremental basis the 1968 cost of El Paso gas at Milpitas in the volumes covered by Alberta and

Southern's application was estimated by Alberta and Southern at 34 cents and by Westcoast at 43 cents per Mcf. This wide divergence is attributable mainly to the fact that Westcoast assumed that both looping and additional compression would be required on PG&E's facilities between the Arizona-California border and Milpitas, whereas the witness for Alberta and Southern, an official of PG&E responsible for the gas system design and the pipe line in question, testified that if these facilities had to be expanded to carry the additional gas, compressors would be added but no additional looping would be undertaken. Alberta and Southern and Westcoast were agreed that the incremental cost of Alberta gas at Antioch would in 1968 be somewhat less than 25 cents per Mcf and that the incremental cost of British Columbia gas would be approximately 36 cents per Mcf.

Alberta and Southern testified that the average price of El Paso gas at the Arizona-California border had declined from 34.6 cents per Mcf in 1962 to 33.3 cents in 1963 and to 30.0 cents in 1964. Further reductions might be anticipated as a result of larger volumes passing through the line if additional quantities of El Paso gas rather than Alberta and Southern gas were to be purchased by PG&E. It was estimated by Alberta and Southern that such reductions might bring the incremental cost of El Paso gas at the Arizona-California border to as low as 23 cents, depending on the extent to which El Paso might have excess gas supplies

and unused capacity in its system. With reference to the last mentioned figure, Alberta and Southern admitted that it would not expect gas could be purchased at that price. Rather it represented the minimum at which El Paso could afford to sell gas and any higher price would improve that company's profit position.

The Province of British Columbia

In its intervention the Province of British Columbia stated that it was a requirement of the national interest of Canada that all gas producing areas of Canada should be afforded equal opportunity and incentive to develop and that the Board give consideration to the potential markets for natural gas, both within and without Canada, and determine the markets to which gas from various producing areas should be directed. In addition, the Board should ensure that all gas transmission companies be afforded an equal opportunity to market exportable gas, provided that available supplies should first be directed by the transmission company to the export area most economically appropriate to its production areas.

It was submitted that any increase in exports of gas to states bordering on the Pacific Ocean should be taken from fields in British Columbia, the Yukon and the Northwest Territories. Approval of Alberta and Southern's application would, it was suggested, be contrary to the policy of the National Energy Board as set forth in the two Reports to the Governor in Council referred to in Westcoast's submission.

It was contended that, having due regard to the requirements of Canadian markets and all other factors being equal, gas providing the greatest economic incentive for development of new producing areas should be allocated to export markets. Using the vicinities of Vancouver and Calgary as the respective delivery centres for British Columbia and Alberta gas, it was stated that the straight line distance from these centres to San Francisco was approximately 150 miles less for British Columbia gas than for Alberta gas. This was more than offset, however, by the fact that the distance from the respective sources to these delivery centres was much greater in the case of British Columbia gas. The competitive advantage of Calgary over Vancouver in moving gas to Eastern markets was stated to be some 400 miles. In the circumstances it was said to be in the national interest that the West Coast markets of the United States be served from the Vancouver delivery point before export gas was "diverted from the eastern markets".

The Board's decisions in 1960 and 1964, already referred to, had tended to encourage the development of gas fields in Northern British Columbia. Other fields remain to be developed, however, and the greatest impetus towards this development would be the furnishing of an available market. Exploration and development of further gas reserves in these areas would be of benefit to Canada as a whole and the present unsatisfactory rate of development was attributed to competition from both Canadian and United States sources. Unless the market represented by the states bordering on the

Pacific Coast was primarily reserved for gas from Northern British Columbia and adjacent territory in Northern Alberta, economic development of the area would be set back. A distinction was drawn between British Columbia exploration, which had been directed primarily to the discovery of natural gas, and gas discoveries in Alberta, which were said to have resulted from exploration for new oil producing areas.

In the Province's submission it was contended that gas from Northern British Columbia could be delivered to the California border at a price competitive with gas available from United States sources. It was submitted that Canadian sources should not compete with one another to the extent that Canadian prices were lowered to the benefit of consumers in the United States.

Testifying on behalf of the Province of British Columbia, the Attorney General stated that the National Energy Board had the necessary authority to examine total Canadian resources and to decide how these resources were to be employed. Allocation of gas for export sales was a function which the Board could properly exercise or, alternatively, it could be vested with the necessary powers.

It was stated that, in approaching the problem within Alberta, that province had recognized that there were a number of factors which had to be levelled out within its own jurisdiction to avoid the possibility of certain fields being drawn upon more heavily than others. It was suggested

that the Board should recognize disparities among various parts of the country and that in the national interest disparities, particularly in terms of export, should be removed. The Province of British Columbia subscribed to the principle of freedom of contract in the commercial world but it was open to the Board to inquire into any contract to determine whether it was totally in the national interest from all points of view.

Reference was made to the importance to Canada of the California market for gas. By contrast, the States of Washington and Oregon had a population growth which was the slowest on the whole of the Pacific Coast and it was unreasonable to suggest that Westcoast should be confined to that area.

The Attorney General said that, while British Columbia recognized that the California market would continue to be served largely from United States sources, it believed that there was room also for both British Columbia and Alberta gas in that market. Excessive competition between Canadian producers was undesirable but the competitive price in California had to be met and this could be done by selling a mixture of higher and lower cost gas. The analogy was drawn of "high-grading" the resources of a mine and the desirability was stressed of avoiding such a situation in the development of Canadian hydrocarbon resources as a result of excessive competition.

Questioned as to the effect that some direction of the Board designating the area in which United States customers must purchase gas might have on agencies looking after the buyers' interests, the Attorney General suggested that if it were Canadian policy for gas to be sold in one area rather than another this would be recognized as a proper exercise of Canadian discretion. What effective action could be taken by the Board, however, in regard to competition from United States sources was considered to be a major problem calling for consultation between all the parties concerned.

Although both Westcoast's submission and that of the Province of British Columbia called for rejection of Alberta and Southern's application, the Attorney General recognized the difficulty of asking the Board to reject a firm contractual arrangement in favour of one which was neither firm nor contractual and which was much more nearly marginal from the economic standpoint. He suggested that what was required might be some modification which would result in a melding of the various factors in the development of a Canadian export position.

Counsel for the Province of British Columbia, in support of these comments, urged the Board to make a statement of policy as to where gas to be exported must be taken from. The Board possessed the necessary powers under Sections 81 and 82 of the National Energy Board Act and the Province would be satisfied with such a statement of

policy rather than denial of the application as requested in the intervention. The natural, logical, economic area which should be supplied from British Columbia included northern California and any export licence issued to Alberta and Southern in these circumstances should have a much shorter period than 25 years.

#### The Province of Alberta

The submission filed by the Province of Alberta stated that the principle of free competition for export markets for gas was supported by the Province and suggested that where under free competition contracts had been entered into and the gas was found to be surplus to the requirements of Canada there should be no interference with the contracts. No direct reference was made in the submission to Westcoast's proposal that British Columbia gas be exported to California in lieu of further quantities of Alberta gas (the Alberta submission antedated that of British Columbia).

The Premier of Alberta stated that the primary reason for the Province's intervention was the fact that the Government of British Columbia had decided to appear as an Intervenor to block a recommendation of the Oil and Gas Conservation Board and of the Government of Alberta.

The Premier stated that Alberta considered it reasonable for British Columbia to try to gain entrance to the Pacific Northwest market and particularly to the California

market, but that this should be as a result of free open competition with the producers of Alberta rather than through the actions of a regulatory board. Interference with normal negotiation of contracts would shake the confidence of both purchasers and regulatory authorities in the United States as to the value of Canada as an assured source of long-range supply of natural gas. Further, it would be beyond the intention of Parliament as set out in the National Energy Board Act for the Board to direct that gas from a certain area of Canada was the only gas that would be permitted to enter a particular export market. The Board's responsibility lay in dealing with the national interest, not with the interests of one region or one province as against the interests of others. Nor did he consider that the Board had any responsibility in regard to comparison of the delivered price of Canadian gas in the market area with the cost of gas coming from alternative sources. This was an integral part of price negotiation in the open market.

It was suggested by the Premier that the ability of British Columbia gas to penetrate the California market area would be solely a matter of price. The special relationship of PG&E to its affiliated companies in Alberta would not confer any particular advantage on Alberta gas. Alberta gas currently moving to the California market had been barely competitive there with supplies from other sources. This did not mean that it could be considered cheap gas.

Although Alberta gas was more competitive in the California market than British Columbia gas, Alberta producers received a higher well-head price than did producers in British Columbia.

The Premier stated that in his view there was no parallel between Alberta's prorationing of oil production and the allocation of markets proposed by Westcoast and the Province of British Columbia, although one of the effects of prorationing was the orderly marketing of Alberta's oil production.

#### Other

In its submission the CPA expressed the view that governments should not easily move to interfere with marketing arrangements made in good faith between producers and marketers with respect to contractable reserves of gas, unless to do so would clearly be in the public interest. It was also stated that contract interference could only impair the effectiveness of the open marketplace which, the Association submitted, was the best forum for allocation of supply to demand.

During the hearing, a representative of the Association, asked whether in effect there is an allocation of markets for crude oil under the Alberta prorationing system, said there definitely was market sharing. In response to another question he said that as a result of the National Oil Policy certain Canadian markets were being

served with Canadian crude oil which might not be so served on a completely free trade basis. Dedication of markets in the case of natural gas in the way proposed by Westcoast and the Province of British Columbia would, in his view, inevitably lead to total regulation of the industry.

He agreed with Counsel for British Columbia that one of the reasons for instituting prorationing of oil production in Alberta to market demand had been to provide an equitable division of the market to the various producers within the Province, but maintained that the principal reason for the introduction of the system, and for its continuation, was conservation.

In the Association's view the main difference between marketing crude oil and marketing natural gas lay in the fact that arrangements between producers and refiners of crude oil were ordinarily on a 30-day basis, whereas natural gas contracts were long-term. Another difference was the fact that producers of natural gas frequently processed the gas themselves to make it marketable, whereas crude oil was processed by the refiners. A third difference was that in the case of gas the direct pipe line connection between the producer and the consumer gave the industry a monopolistic character which had led to it becoming subject to regulation from source to point of consumption, whereas in the case of oil in Canada, the only formal regulation is at the level of provincial control over production.

Conclusions - Both the British Columbia and the Westcoast interventions formally requested the dismissal of the applications of Alberta and Southern and Alberta Natural, but this position was, in the case of the Province, somewhat modified during the course of the hearing.

The pith and substance of these two interventions would appear to be that the Board should, by exercise of its regulatory powers, deny or limit further export of gas from Alberta to California, and at the same time encourage, assist or even, if possible, bring about the development of a market in California for British Columbia gas. In the view of the Intervenors, such action by the Board could be justified on the grounds that it would result in an equalization of opportunity for development of resources and could be achieved by the Board "allocating" the growth, or a part of it, in the California export market to British Columbia gas.

The Intervenors' plea for a policy of selective development, by provinces, of natural gas resources evoked considerable discussion and argument as to the Board's powers to "allocate" markets, and export markets in particular. This discussion centred around Section 82 of the Act. It was the contention of the Province of British Columbia that this section enables the Board to

"say that the gas to be exported must be taken from a particular area" and in this manner to "allocate" markets.

Alberta and Southern argued that the Board did not have the statutory authority to "allocate" markets, let alone to fix well-head prices which, in its view, would be an inevitable concomitant of such a course of action. It associated the Board's powers under Section 82 to restrict the area from which gas may be drawn with the issue of an export licence. In this context, there was no doubt of the Board's powers; indeed, "there is no question in the world that the Board should say the fields and the areas (from) which the gas should be exported...".

The CPA contended that, had Parliament intended the Board to have power to "allocate" markets, then, "having regard to the broad economic and political implications involved Parliament would have defined it, even as it had done with respect to those less contentious but specified areas of authority described in sub-clauses (a) and (b) of Section 83".

The question in issue seems to be whether the Board should declare a general policy respecting the "allocation" of markets - that it should, to be more precise, say that any additional gas to be exported to the United States, more particularly California, must come from specific areas in Canada, in this case from British Columbia.

The Board believes that it is neither practicable nor desirable to enunciate a general policy regarding the "allocation" of markets in the sense proposed by the Intervenors.

The Canadian natural gas industry, in the years since large quantities of gas became available for marketing outside the original areas of discovery, has been characterized by a very rapid pace of development indeed. The Board has no doubt that the ingenuity and enterprise of those in the industry will cause its development to continue at a very substantial rate, and to broaden out, as has been the pattern in past years, from original areas of prolific discovery to more remote areas, as the establishment of reserves and of markets makes feasible the extension from area to area of the means of transmission of gas from source to market. Recent years have demonstrated that this broadening can be accomplished in such a way that attractive field prices can be paid to producers while unit transmission costs are reduced to an extent which maintains the competitive capacity of Canadian gas in the market. This capacity to pay such prices to producers while continuing to compete in the market is what provides, under our system of enterprise, the real incentive for exploration. It appears to the Board that to attempt to encourage development in one area of the country rather than another

in spite of competitive disadvantages, would be more likely in the long run to impair than to assist the orderly and sound development of a gas industry in Canada capable of competing not only in Canadian markets but in those United States markets to which Canadian gas may penetrate.

Westcoast and the Province of British Columbia quoted from past reports of the Board, and from statements of former Ministers of Trade and Commerce, and argued that the quotations established general policies consistent with the viewpoint of these Intervenors. That the way in which these statements were interpreted was not universally acceptable was demonstrated by the intensity with which various counsel questioned the Intervenors concerning them. Perhaps the best summing up of their relevance to the proceedings was that given by the Honourable Mr. Bonner, i.e.: "Quite frankly, we put the broadest interpretation on the Board's remarks and hoped for the best". So far as the quotations from Board reports are concerned, the Board in each case was addressing itself to the particular circumstances of the application then before it, not to broad general policy in the sense argued by the Intervenors. Nothing in those quotations, each considered in its context, is in the view of the Board inconsistent with the position here taken.

As to the specific proposal of Westcoast, the Board wishes to comment only on certain of its vital aspects.

The surplus of gas reserves in British Columbia and the Peace River area of Alberta as of 31 December 1964 is estimated by the Board to be 2.2 Tcf. Since the Board has found that 2.3 Tcf of reserves would be required to protect the volumes which the Board is prepared to authorize Alberta and Southern to export, and since Westcoast's proposal would merely substitute similar volumes of British Columbia gas for Alberta gas, it is apparent that reserves of gas in British Columbia and the Peace River district of Alberta would just support Westcoast's proposal, with no margin for additional sales to the United States Pacific Northwest or other markets outside British Columbia.

Either on an incremental cost or on a rolled-in cost basis, the proposed substitution of British Columbia gas for additional exports of Alberta gas to the California market would result in the additional supplies of Canadian gas costing more in that market. This fact Westcoast itself admits.

The Board is not satisfied that a mixture of Alberta and British Columbia gas as proposed by Westcoast could reach Northern California at a price which would be competitive with the present or probable future prices of gas supplied by El Paso via Topock. In this connection

PG&E, in rejecting the proposal submitted to it by West-coast, stated that its alternative supply would be gas from the Southwestern United States delivered by El Paso via Topock since the cost of such gas in the San Francisco area "would be much lower than the delivered cost of (Westcoast's) gas". This statement was not invalidated by the evidence.

These observations are academic at the present time, however, since Westcoast's proposal is not the subject of an export application.

The Board has carefully considered the interventions of the Province of British Columbia and of West-coast, and all representations made in relation to them, but has concluded that these do not justify rejection or modification of the application of Alberta and Southern.

All the foregoing comments are of course without prejudice to any future application by Westcoast for a licence to export gas.

## DISPOSITION

The Board's conclusions in regard to the applications before it are stated separately in the sections of this Report dealing with the individual applications.

The Board is accordingly prepared, subject to the approval of the Governor in Council, to issue:

To Alberta and Southern Gas Co. Ltd.

An order amending Licence No. GL-3 as follows:

(a) by adding to condition (2) of the said Licence GL-3 the following:

"provided that, notwithstanding the limitations in the quantity of gas that may be exported in any one day, and for the purpose only of alleviating temporary operating problems caused by pipeline or equipment failure, the quantity of gas that may be exported in any one day shall be 110 per cent of the quantity of gas that may otherwise be exported in any one day";

(b) by deleting the whole of condition (3) of the said Licence GL-3 and substituting therefor the following:

"(3) the Licencee shall comply with all valid terms and conditions of Permit No. 64-3 dated 1 December 1964 issued to it by the Oil and Gas Conservation Board of Alberta";

(c) by deleting the whole of condition (4) of the said Licence GL-3 and substituting therefor the following:

"(4) the prices to be received from time to time by the Licencee for the gas to be exported hereunder shall be not less than those specified in the gas sale contract dated 31 January 1961 as amended by agreement dated 31 December 1962 between the Licencee and Pacific Gas Transmission Company filed with the Board";

and,

a new licence for the exportation of gas at a place on the international boundary line between Canada and the United States of America near Kingsgate, British Columbia, subject to the following terms and conditions:

- (1) The term of the licence shall be for a period commencing on 1 November 1966 and ending 31 October 1989;
- (2) The quantity of gas that may be exported under the authority of and in accordance with the licence shall not exceed:
  - (a) for the period from 1 November 1966 to 31 October 1967, 113,125,000 cubic feet in any one day or 37,415,000,000 cubic feet for the period;

- (b) for the period from 1 November 1967 to 31 October 1989, 226,250,000 cubic feet in any one day or 74,830,000,000 cubic feet in any consecutive twelve-month period ending on 31 October;
  - (c) for the term of the licence, 1,614,000,000,000 cubic feet.
- (3) Notwithstanding the provisions of condition (2), and for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, the quantity of gas that may be exported in any one day shall be 110 per cent of the quantity of gas that may otherwise be exported in any one day;
- (4) The Licencee shall comply with all valid terms and conditions of Permit No. AS 64-3 dated 1 December 1964 issued to it by the Oil and Gas Conservation Board of Alberta;
- (5) The prices to be received from time to time by the Licencee for the gas to be exported hereunder shall be not less than those specified in the contract dated 31 January 1961 between the Licencee and Pacific Gas Transmission Company, as amended by agreements dated 31 December 1962 and 21 May 1964, all filed with the Board;

(6) The quantity, specific gravity and higher heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licencee, in a manner approved by the Board, at the place of export on the international boundary line between Canada and the United States of America.

To Canadian-Montana Pipe Line Company

An order amending Licence No. GL-5 as follows:

By deleting the whole of condition (3) of the said Licence No. GL-5 and substituting therefor the following:

"(3) the prices to be received from time to time by the Licencee for gas to be exported hereunder shall not be less than those computed in accordance with the contract dated 9 November 1961 between the Licencee and The Montana Power Company filed with the Board";

and,

a new licence for the exportation of gas at a place on the international boundary line between Canada and the United States of America near Cardston, Alberta, subject to the following terms and conditions:

(1) The term of the licence shall be for a period commencing on 1 November 1966 and ending 31 October 1989;

- (2) The quantity of gas that may be exported under the authority of and in accordance with the licence shall not exceed:
- (a) for the period from 1 November 1966 to 31 October 1967, 12,000,000 cubic feet in any one day or 3,650,000,000 cubic feet for the period;
- (b) for the period 1 November 1967 to 31 October 1989, 24,000,000 cubic feet in any one day or 7,300,000,000 cubic feet in any consecutive twelve-month period ending on 31 October;
- (c) for the term of the licence, 109,500,000,000 cubic feet.
- (3) The prices to be received from time to time by the Licencee for the gas to be exported hereunder shall be not less than those computed in accordance with the contracts dated 9 November 1961 and 25 May 1964 between the Licencee and The Montana Power Company, both filed with the Board;
- (4) The quantity, specific gravity and higher heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licencee, in a manner approved by the Board, at the place of export on the international boundary line between Canada and the United States of America.

To Trans-Canada Pipe Lines Limited

A licence for the exportation of gas at a place on the international boundary line between Canada and the United States of America near Emerson, Manitoba, subject to the following terms and conditions:

- (1) The term of the licence shall be for a period commencing 1 November 1965 and ending 31 October 1989;
- (2) The quantity of gas that may be exported under the authority of and in accordance with the licence shall not exceed 186,000,000 cubic feet in any one day or 68,000,000,000 cubic feet in any consecutive twelve-month period ending on 31 October or 1,632,000,000,000 cubic feet during the term of the licence;
- (3) Notwithstanding condition (2), as a tolerance, the amount the Licencee may export may, in any twenty-four-hour period, exceed the quantity of 186,000,000 cubic feet by two per cent of that amount;
- (4) The Licencee shall comply with all valid terms and conditions of Permit No. TC 64-6 dated 1 December 1964 issued to it by the Oil and Gas Conservation Board of Alberta;
- (5) The prices to be received from time to time by the Licencee for the gas to be exported shall not be less than those prices specified in a letter from

Midwestern Gas Transmission Company to Trans-Canada Pipe Lines Limited dated 10 November 1964, which was placed in evidence before the Board as Exhibit 16;

- (6) The quantity, specific gravity and higher heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licencee, in a manner approved by the Board, at the place of export on the international boundary line between Canada and the United States of America.
- (7) The Licencee shall, upon the issue of this licence, forthwith tender to Midwestern Gas Transmission Company, in accordance with the terms of the option contained in the contract between it and the Licencee dated 14 April 1960, the full volumes of gas authorized herein for export;
- (8) The Licencee shall, within one hundred and ten days after the day of issue of this licence, inform the Board of those volumes of gas, if any, which Midwestern Gas Transmission Company has elected to purchase pursuant to the option referred to in condition (7).

Subject to the approval of the Governor in Council the Board is prepared to issue:

To Alberta Natural Gas Company

An order amending Certificate No. GC-12 as follows:

(a) by deleting therefrom the following words "107 miles, to a place on the international boundary line between Canada and the United States of America near Kingsgate, British Columbia, together with a compressor station, meter stations, and other works connected therewith as set forth in the application. The general location of the said pipe line is set forth in the map marked 'Appendix A'; the design data, compressor station, meter stations, and other works connected with the said pipe line are more particularly described and set forth in the schematic diagram marked 'Appendix B'; Appendices A and B are annexed to and form part of this Certificate" and substituting therefor the following words:

"106 miles, to a place on the international boundary line between Canada and the United States of America near Kingsgate, British Columbia, together with a compressor station, meter stations and other works connected therewith. The general location of the said pipe line, in respect of which this Certificate is issued, is as shown on a route map, designated

Drawing No. 2096-M, dated the 9th day of June 1965, and the design data, internal pressures and specifications thereof are more particularly described and set forth in a schematic diagram, designated Drawing No. 2097-M dated the 9th day of June 1965, both of which drawings are filed with the Board under File No. 8-1-2-1";

- (b) by deleting condition (1) and substituting the following:

"(1) the said pipe line shall be the property of and be operated by the Company";

- (c) by deleting condition (3) and substituting the following:

"(3) the construction of the said pipe line, the compressor station, meter stations, and other works connected therewith shall be in accordance with the specifications and details as submitted to the Board and no change in the design data, internal pressures and specifications of the pipe line as set forth in the said schematic diagram shall be made without the prior approval of the Board";

and,

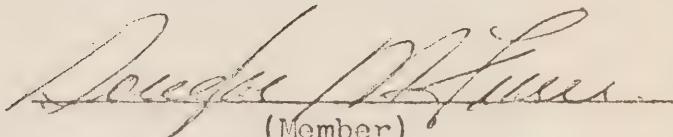
A certificate of public convenience and necessity for the construction and operation of certain additional pipe line facilities as set forth in the application subject to the following terms and conditions:

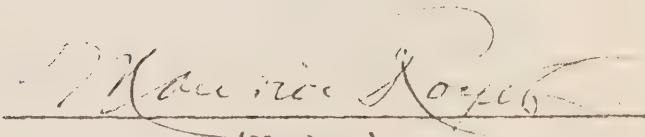
- (1) The pipe line facilities shall be the property of and be operated by the Company;
- (2) The pipe line facilities shall be constructed and installed in accordance with those specifications set forth in the application, and no change in the design data, internal pressures and specifications of the pipe line system, including the said additional pipe line, as set forth designated Drawing No. 2097-M; Revision 1, on record with the Board, in the said schematic diagram, shall be made without the prior approval of the Board.
- (3) The testing of the pipe line facilities shall be carried out in conformity with the Board's requirements.
- (4) The construction and installation of the pipe line facilities shall be completed by 31 December 1967 unless, upon application by the Company, a later day is fixed by the Board and approved by the Governor in Council

9-11

All of which is respectfully submitted.

  
\_\_\_\_\_  
(Chairman)

  
\_\_\_\_\_  
(Member)

  
\_\_\_\_\_  
(Member)

July 1965



EXTRACTS FROM THE APPLICATIONS

Alberta and Southern Gas Co. Ltd.

For an order varying Licence No. GL-3 in the following respects:

By adding to condition (2) of the said Licence No. GL-3 the following:

"provided that, notwithstanding the limitations in the quantity of gas that may be exported in any one day, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, the quantity of gas that may be exported in any one day shall be 110 per cent of the quantity of gas that may otherwise be exported in any one day;"

By deleting the whole of condition (3) of the said Licence No. GL-3 and substituting therefor the following:

"(3) the licensee shall comply with all valid terms and conditions of any authorization obtained from the provincial authority to remove the gas to be exported hereunder from the province in which such gas is produced."

By deleting the whole of condition (4) of the said Licence No. GL-3 and substituting therefor the following:

"(4) the prices to be received from time to time by the licensee for the gas to be exported hereunder shall be not less than the cost of service charge as provided in the gas sale contract dated 31 January 1961 as amended by agreement dated 31 December 1962 between the licensee and Pacific Gas Transmission Company and filed with the Board."

And for a further licence for the exportation of gas at a place on the international boundary between Canada and the United States of America near Kingsgate in the Province of British Columbia, subject to the following terms and conditions:

(1) that the duration of the licence shall be for a period commencing on the day of its issue and ending on 31 October 1989;

(2) that the maximum quantity of gas that may be exported under the authority of and in accordance with the licence shall be a quantity which when added to the quantity that may be contemporaneously exported under the authority of and in accordance with Licence No. GL-3 shall produce the following total quantity, namely,

685,000,000 cubic feet in any one day;

228,100,000,000 cubic feet in any one year ending the 31st day of October;

5,900,000,000,000 cubic feet during the term of the licence

or, in the alternative to the foregoing terms in this clause (2) contained, such terms as will license the Applicant to export the daily, yearly and total quantities of gas mentioned in this clause (2) under the authority of and in accordance with the licence herein applied for and Licence No. GL-3;

(3) that, notwithstanding the limitations in the quantity of gas that may be exported in any one day, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, the quantity of gas that may be exported in any one day shall be 110 per cent of the quantity of gas that may be otherwise exported in any one day.

Alberta Natural Gas Company

For an order to vary Certificate No. GC-12 by:

(i) striking out the whole of the last paragraph on the first page thereof and substituting therefor the following:

"NOW THEREFORE the National Energy Board, pursuant to section 44 of the National Energy Board Act, hereby issues this certificate of public convenience and necessity to Alberta Natural Gas Company in respect of a 36-inch O.D. pipe line for the transmission of gas, extending from its junction with the pipe line of The Alberta Gas Trunk Line Company Limited

at a place in Section 17, Township 8, Range 5, West of the fifth meridian in the Province of Alberta, thence generally in a south-westerly direction through the Crowsnest Pass and the Province of British Columbia, a distance of approximately 106 miles, to a place on the international boundary line between Canada and the United States of America near Kingsgate, British Columbia. The general location of the said pipe line is set forth in the map dated April 1st, 1960 and revised October 19th, 1960, filed with the Board, and the design data of the said pipe line are set forth and described in the schematic diagram dated March 28th, 1960, and revised October 19th, 1960, filed with the Board."

(ii) by striking out the whole of condition numbered (1) on the second page thereof and substituting therefor the following:

"(1) the said pipe line shall be the property of and be operated by the Company;"

(iii) by striking out the whole of condition numbered (3) on the second page thereof and substituting therefor the following:

"(3) the construction of the said pipe line shall be in accordance with the plans and specifications thereof submitted to and approved by the Board."

And for a further certificate of public convenience and necessity in respect of the following facilities:

A. New Compressor Station

Compressor Station No. 2B, to be located near mile post 80 on the Applicant's pipe line, and to contain one 8000 HP turbine-driven centrifugal compressor.

B. Addition to Existing Compressor Station

The addition of two 3400 HP gas engine driven reciprocating compressor units at the Applicant's Compressor Station No. 1 located at mile post 2.9 on the Applicant's pipe line.

C. Addition to Meter Station

The addition of three twenty-inch meter runs to the Applicant's Kingsgate meter station.

or, in the alternative, for an order exempting the Applicant from compliance with the provisions of sections 25 to 29 of the said Act in respect of the said facilities.

Canadian-Montana Pipe Line Company

For an order amending Licence No. GL-5 as follows:

By deleting the whole of condition (3) of the said Licence No. GL-5 and substituting therefor the following:

"the prices to be received from time to time by the licensee for gas to be exported hereunder shall not be less than the cost of service charged as provided in the agreement dated the 9th day of November, 1961, between the licensee and The Montana Power Company and filed with the Board;"

And for a further licence for the exportation of gas from Canada at a point on the International Boundary between Canada and the United States in Section 4, Township 1, Range 25, West of the 4th Meridian in the Province of Alberta, subject to the following terms and conditions:

- (1) That the duration of the licence shall be for a period commencing on the day of its issue and ending on the 31st day of October, 1989;
- (2) That the maximum quantity of gas that may be exported under the authority of and in accordance with the licence shall be a quantity which when added to the quantity that may be contemporaneously exported under the authority of and in accordance with Licence No. GL-5, shall produce the following total quantities, namely:

an average daily quantity of 50,000,000 cubic feet, but not to exceed 60,000,000 cubic feet in any one day;

18,250,000,000 cubic feet in any one year  
ending the 31st day of October;

416,100,000,000 cubic feet during the term  
of the licence.

Trans-Canada Pipe Lines Limited

For a licence for the exportation of gas at  
a place on the international boundary between  
Canada and the United States of America near  
Emerson in the Province of Manitoba during a  
twenty-five year period commencing on the 1st  
day of November, 1965, in the following  
quantities, namely, not more than one hundred  
and eighty-six million (186,000,000) cubic  
feet in any one day nor more than sixty-eight  
billion (68,000,000,000) cubic feet in any  
consecutive twelve-month period, nor more than  
one trillion, seven hundred billion  
(1,700,000,000,000) cubic feet during the total  
period; provided that there may be exported in  
any one day a volume not in excess of 102% of  
the said daily limitation of one hundred and  
eighty-six million (186,000,000) cubic feet,  
all volumes measures at 14.73 psia and 60°  
Fahrenheit.



Appendix 2, Table 1

		TOTAL OF CANADIAN DEMAND FOR NATURAL GAS																						
		BY PROVINCE AND CATEGORY OF USE - FROM 1965 TO 1976 INCLUSIVE																						
		(billions of cubic feet at standard conditions 14.75 p.s.i.a., 60° F., 1,000' Barst.)																						
Province	Category	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Alberta	-Residential	8.7	9.7	10.3	10.9	12.1	13.6	14.7	17.1	18.2	20.7	22.1	23.5	24.0	24.7	31	35.3	34.6	36.6	40.6	42.7	52.6	64.5	65.4
	-Commercial	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8
	-Industrial	1.5	2.0	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.8	4.0	4.2	4.4	4.6	4.8	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8
	Total Sales	14.5	16.5	18.6	19.9	21.0	22.6	24.6	26.7	28.1	30.4	32.6	34.2	35.9	37.4	39.4	41.6	43.3	44.5	45.7	46.9	48.7	50.3	51.4
British Columbia	-Residential	4.1	5.0	5.9	7.0	8.1	9.7	10.5	11.1	11.7	12.0	12.5	13.5	14.2	14.9	15.5	16.2	16.7	17.2	17.7	18.2	18.7	19.2	19.7
	-Commercial	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3
	-Industrial	4.6	5.9	6.9	10.4	11.7	13.2	14.6	16.0	18.2	20.5	21.5	22.7	24.0	26.1	27.5	29.0	30.7	31.6	32.5	33.4	34.3	35.2	36.1
	Total Sales	10.7	12.7	14.6	16.1	17.8	19.3	20.9	22.7	24.3	26.6	27.6	29.4	31.1	32.9	34.6	36.1	37.7	39.2	40.7	42.0	43.7	45.2	46.8
Saskatchewan	-Residential	2.1	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.8	4.0	4.2	4.4	4.6	4.8	5.0	5.2	5.4	5.6	5.8	6.0	6.2	6.4	6.6
	-Commercial	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7
	-Industrial	1.0	1.2	1.4	1.6	1.8	2.0	2.2	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.8	4.0	4.2	4.4	4.6	4.8	5.0	5.2	5.4
	Total Sales	1.5	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.3	5.5	5.7	5.9
Manitoba	-Residential	10.5	11.6	12.6	13.6	14.6	15.6	16.6	17.6	18.6	20.2	21.6	22.6	23.6	24.6	25.6	26.6	27.6	28.6	29.6	30.6	31.6	32.6	33.6
	-Commercial	2.5	2.7	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.3	5.5	5.7	5.9	6.1	6.3	6.5	6.7	6.9
	-Industrial	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2
	Total Sales	1.5	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.3	5.5	5.7	5.9
Quebec	-Residential	10.0	10.5	11.0	11.5	12.0	12.5	13.0	13.5	14.0	14.5	15.0	15.5	16.0	16.5	17.0	17.5	18.0	18.5	19.0	19.5	20.0	20.5	21.0
	-Commercial	2.0	2.2	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.8	4.0	4.2	4.4	4.6	4.8	5.0	5.2	5.4	5.6	5.8	6.0	6.2	6.4
	-Industrial	1.5	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.3	5.5	5.7	5.9
	Total Sales	1.5	1.7	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.3	5.5	5.7	5.9
Nova Scotia	-Residential	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7
	-Commercial	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6
	-Industrial	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7
	Total Sales	2.4	2.7	3.0	3.3	3.6	3.9	4.2	4.5	4.8	5.1	5.4	5.7	6.0	6.3	6.6	6.9	7.2	7.5	7.8	8.1	8.4	8.7	9.0
P.E.I.	-Residential	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6
	-Commercial	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3
	-Industrial	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3
	Total Sales	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.8
Pipe Line Fuel & Losses		2.0	4.0	5.0	5.5	5.9	6.0	6.1	6.5	6.6	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.8	7.9	8.0	8.1
Pipe Line Demand East of B.C.		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Subtotal		276.6	282.0	287.1	291.0	295.5	299.7	303.9	307.9	312.1	316.5	320.7	325.0	329.5	333.7	337.8	341.8	345.8	349.8	353.8	357.8	361.8	365.8	369.8
Pipe Line Fuel & Losses		0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total Canadian Demand		320.2	325.6	330.7	336.1	341.3	346.7	351.9	357.8	363.1	369.7	376.6	383.5	390.1	397.1	403.9	410.7	417.5	424.3	431.1	437.9	444.7	451.5	458.3



Appendix 2. Table 2

Year	ESTIMATES NATURAL GAS MARKET REQUIREMENTS IN CANADA BY PROVINCES 1965-1994												ESTIMATES NATURAL GAS MARKET REQUIREMENTS IN CANADA BY PROVINCES 1965-1994																											
	ONTARIO				MANITOBA				SASKATCHEWAN				ALBERTA				PEAK & LOSSES				TOTAL EAST OF B.C.				BRITISH COLUMBIA				PEAK & LOSSES				TOTAL BRITISH COLUMBIA				TOTAL CANADA			
	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %	Annual Bcf	Peak Mcf/d	L.P. %							
1965	34.6	98	85.9	211.5	1,032	56.7	29.7	166	48.9	48.7	296	54.3	59.7	46.0	210	59.9	55.7	2,677	57.0	47.4	233	55.8	5.0	29	55.8	55.3	262	55.8	56.9	610.0	2,939	56.9	1965							
1966	35.6	109	89.2	230.2	1,109	56.9	31.4	177	48.6	51.7	261	54.2	59.8	48.9	223	60.0	59.0	2,849	56.9	53.1	250	56.4	6.5	32	56.4	59.7	290	56.4	56.9	651.7	3,139	56.9	1966							
1967	36.8	112	90.0	259.2	1,215	57.5	33.3	189	48.4	54.9	278	54.1	216.8	1,059	56.2	53.6	211	57.0	64.6	3,092	57.6	59.4	286	57.0	7.6	36	57.0	66.6	322	57.0	57.5	716.4	3,414	57.5	1967					
1968	30.1	113	88.5	279.5	1,335	57.7	35.5	209	48.1	58.3	295	54.0	284.5	1,089	56.3	57.2	254	61.5	69.2	3,208	57.7	66.4	314	57.7	8.3	39	57.7	74.7	353	57.7	57.7	787.6	3,635	57.7	1968					
1969	39.4	133	81.0	305.0	1,447	57.9	37.6	215	47.9	62.0	315	53.9	235.1	1,132	56.4	63.0	273	61.2	73.0	3,515	57.6	74.3	349	58.3	9.3	44	58.3	85.4	393	58.3	57.7	822.5	3,906	57.7	1969					
1970	40.5	150	74.0	334.0	1,597	58.1	40.0	229	47.8	66.0	335	53.8	65.0	2172	62.0	66.0	304	61.5	766.0	3,752	57.5	83.5	587	59.0	10.0	48	59.1	93.0	593	59.0	57.6	880.7	4,057	57.6	1970					
1971	43.1	162	74.0	358.0	1,659	58.1	42.5	244	47.8	68.3	350	53.5	249.3	1,211	56.4	68.0	304	61.5	832.3	3,938	57.4	87.1	402	58.9	10.9	51	58.7	88.7	597	58.7	57.6	921.2	4,345	57.6	1971					
1972	45.9	179	74.0	370.0	1,793	58.1	45.0	258	47.7	70.6	368	53.5	273.0	1,271	56.4	70.0	314	61.6	879.7	4,027	57.5	92.5	424	58.7	11.3	53	58.3	102.0	500	58.5	977.8	4,527	57.8	1972						
1973	49.0	181	74.0	391.0	1,849	58.1	47.0	276	47.6	72.9	379	53.0	280.1	1,346	57.1	75.7	337	61.6	916.6	4,350	57.6	94.6	445	58.3	11.8	53	58.3	1,023.0	4,859	57.9	1973									
1974	50.4	190	74.0	404.0	1,902	58.1	50.0	294	47.8	75.6	389	52.8	283.3	1,393	56.9	79.2	350	61.6	959.2	4,565	57.6	98.6	466	58.0	12.3	58	58.0	1,070.1	5,069	57.6	1974									
1975	52.7	206	74.0	435.9	2,065	58.1	53.7	316	47.3	76.0	402	52.5	260.0	1,447	56.9	62.0	168	61.6	1,002.7	4,776	57.5	109.8	488	57.7	12.9	61	57.7	1,118.6	5,375	57.5	1975									
1976	55.0	218	74.0	458.5	2,130	58.0	56.5	322	48.0	80.1	418	52.4	307.0	1,483	56.8	86.0	380	61.8	1,091.7	4,953	57.5	106.3	505	57.5	13.5	63	57.5	1,181.3	5,519	57.5	1976									
1977	62.6	232	74.1	471.0	2,231	57.9	59.5	359	48.0	82.6	432	52.2	317.0	1,539	56.6	89.5	377	61.7	1,083.6	5,120	57.6	109.8	508	57.2	13.7	65	57.2	1,207.1	5,765	57.6	1977									
1978	66.4	246	74.0	492.2	2,351	57.8	67.5	356	48.7	84.7	445	52.2	320.0	1,585	56.5	92.9	413	61.6	1,125.5	5,376	57.4	94.6	596	56.9	13.8	68	56.9	1,257.6	5,998	57.3	1978									
1979	70.4	261	74.0	511.1	2,433	57.8	65.9	359	48.5	87.1	459	52.0	344.6	1,635	56.4	96.6	479	61.7	1,169.9	5,592	57.3	117.5	67	56.7	14.1	70	56.7	1,310.1	6,210	57.3	1979									
1980	74.5	275	74.0	515.8	2,558	57.7	64.4	392	48.4	89.8	473	51.9	346.6	1,660	56.3	100.5	444	61.0	1,216.7	5,803	57.2	121.2	586	56.5	14.2	74	56.5	1,374.0	6,822	57.2	1980									
1981	79.6	291	73.9	516.2	2,644	57.6	72.1	407	48.7	91.7	469	51.9	369.1	1,701	56.2	104.0	479	60.8	1,295.0	5,997	57.1	124.1	587	56.4	14.3	75	56.4	1,401.3	6,715	57.2	1981									
1982	82.8	307	73.9	577.0	2,749	57.5	75.2	422	49.0	93.5	494	52.3	380.0	1,759.9	56.0	109.9	480	61.9	1,110.2	6,210	57.4	152.1	614	56.1	16.1	82	56.1	1,446.6	7,009	57.3	1982									
1983	87.1	303	73.9	599.1	2,859	57.4	78.0	454	49.3	95.0	500	52.0	391.1	1,805	56.7	112.7	499	63.9	1,365.0	5,517	57.4	135.3	659	56.2	16.9	83	56.2	1,517.2	7,259	57.3	1983									
1984	91.0	310	74.1	621	2,965	57.3	81.6	450	49.6	97.1	514	51.9	501.0	1,850	56.6	116.7	514	62.1	1,413.8	6,729	57.4	140.6	668	56.1	17.6	86	56.1	1,571.4	7,500	57.2	1984									
1985	94.5	317	74.0	669.7	3,072	57.2	85.2	466	49.9	99.7	527	51.9	513.6	1,916	56.5	120.9	533	62.1	1,464.6	6,995	57.4	145.6	712	56.0	18.2	89	56.0	1,613.0	7,796	57.2	1985									
1986	100.5	325	74.1	669.3	3,208	57.2	87.9	460	50.1	101.6	536	51.9	526.9	1,971	56.5	124.8	551	62.0	1,511.5	7,229	57.4	149.9	733	56.0	18.7	91	56.0	1,678.4	8,040	57.2	1986									
1987	105.4	320	74.0	682.0	3,325	57.1	90.7	469	50.3	105.7	548	51.9	539.6	1,986	56.5	128.7	560	62.1	1,559.1	7,495	57.3	154.0	755	56.0	19.2	93	56.0	1,732.0	8,292	57.2	1987									
1988	110.1	400	74.0	719.7	3,430	56.9	91.5	500	50.6	106.1	559	51.8	540.6	2,130	56.5	132.7	585	62.2	1,607.5	7,662	57.3	159.1	777	56.0	20.5	94	56.0	1,794.4	8,576	57.2	1988									
1989	115.2	423	74.0	737.8	3,555	56.8	98.8	520	50.8	107.9	570	51.9	561.2	2,146	56.5	136.8	592	62.2	1,656.9	7,926	57.3	163.1	802	56.0	20.5	102	56.0	1,849.3	9,060	57.1	1989									
1990	120.2	445	74.1	740.0	3,670	56.6	93.3	511	50.6	110.0	581	51.9	496.0	2,110	56.5	140.6	592	62.1	1,715.8	8,136	57.2	173.7	851	56.0	21.0	106	56.0	1,946.6	9,343	57.1	1990									
1991	124.6	460	74.1	740.2	3,787	56.5	101.7	544	51.2	111.7	595	51.9	497.0	2,147	56.5	144.7	620	62.1	1,757.8	8,316	57.2	177.9	851	56.1	22.4	109	56.1	2,001.8	9,460	57.0	1991									
1992	128.7	475	74.0	601.1	3,886	56.5	104.0	554	51.1	114.6	606	51.9	502.7	2,111	56.4	146.6	634	52.1	1,790.7	8,406	57.1	179.1	871	56.1	22.4	109	56.0	2,044.2	9,583	57.0	1992									
1993	133.3	493	74.0	621.7	4,008	56.2	108.4	569	51.4	116.8	617	51.9	516.0	2,108	56.5	152.6	674	52.1	1,897.6	8,489	57.0	184.5	903	56.0	23.1	113	56.0	2,070.7	9,600	56.9	1993									
1994	137.9	510	74.0	642.4	4,132	56.0	108.9	579	51.5	119.0	628	51.9	511.9	2,130	56.5	156.6	693	51.9	1,996.9	9,112	57.0	190.0	930	56.0	23.6	116	56.0	2,110.1	10,158	56.9	1994									





NOTES TO ACCOMPANY APPENDIX 3, TABLE 3

This table shows the net natural gas requirements of British Columbia and of Canadian markets east of Alberta for the 30-year period 1965 to 1994 inclusive.

1. Columns 2, 3 and 4 show the forecast of annual and peak-day requirements, and the resulting load factors, of the net British Columbia market. These values were obtained from Appendix 2, Table 1 after subtracting the estimated requirements for the East Kootenay region. The East Kootenay requirements were based on a separate estimate prepared by the Board staff and were subtracted in order that columns 2, 3 and 4 might show the British Columbia requirements to be served by reserves in British Columbia and gas from the Peace River region of Alberta.
2. Columns 5, 6 and 7 show the forecast of annual and peak-day requirements, and the resulting load factors, of all Canadian markets east of Alberta. These were obtained from Appendix 2, Table 1 and represent the starting point for a determination of the amount of Canadian requirements east of Alberta which will be dependent upon Alberta reserves.
3. Columns 8, 9 and 10 are a forecast of the annual and peak-day production of Canadian natural gas east of Alberta. The Board staff prepared separate forecasts of natural gas production for Saskatchewan and Ontario which were combined to give the results shown.
4. Column 11 lists the estimated total storage and peak-shaving capacity east of Alberta. Separate forecasts were made by the Board's staff for Saskatchewan, Manitoba, Ontario and Quebec. These were combined to give the results shown in Column 11.
5. Columns 12, 13 and 14 show the annual and peak-day volumes of licenced gas imports from the United States, and the resulting apparent load factors, being the ratio of average daily volumes throughout the year to the winter peak-day volumes.
6. Columns 15, 16 and 17 are a forecast of the net Canadian requirements east of Alberta to be served by Alberta gas. Figures in Column 15 were obtained by subtracting those in Columns 8 and 12 from Column 5. Similarly, the figures in Column 16 were obtained by subtracting those in Columns 9, 11 and 13 from Column 6. The values in Column 17 are the resulting load factors associated with the numbers in Columns 15 and 16.

**NET NATURAL GAS REQUIREMENTS OF BRITISH COLUMBIA \***  
**NET CANADIAN NATURAL GAS REQUIREMENTS EAST OF ALBERTA \*\***  
**1,000 BTUS PER CUBIC FOOT**

(1) Year	(2) Net <sup>a</sup> British Columbia Requirements	(3)			(4)			(5)			(6)			(7)			(8)			(9)			(10)			(11)			(12)			(13)			(14)			(15)			(16)			(17)		
		Annual			Peak			LF			Annual			Peak Day			LF			Annual			Peak Day			LF			Storage etc.			Imports From U.S.A.			Net Canadian Requirements East of Alberta											
		Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%	Bcf	MMcf/d	%									
1965	52.7	258	56.0		370.3	1,742	58.2	49.0	203	66.2	434	14.2	124	31.3		307.1	981		85.7																											
1966	58.5	283	56.6		398.8	1,879	58.1	48.5	201	66.1	565	40.5	110	100.9		309.8	1,003		84.6																											
1967	61.0	313	56.9		432.8	2,035	58.2	47.9	199	66.0	619	35.4	96	100.9		349.5	1,121		85.5																											
1968	71.7	339	58.0		468.6	2,193	58.5	48.7	196	65.3	664	30.3	82	101.7		391.6	1,251		85.6																											
1969	80.1	377	58.2		505.8	2,383	58.1	43.0	180	65.5	718	25.2	68	101.2		437.6	1,417		84.6																											
1970	90.0	417	59.1		545.4	2,580	58.0	40.9	171	65.6	787	20.1	54	102.0		481.4	1,568		84.6																											
1971	94.0	438	58.9		573.9	2,717	58.0	38.3	160	65.6	807	15.0	54	76.1		520.6	1,696		84.1																											
1972	97.9	457	58.7		604.6	2,853	58.0	36.0	151	65.4	835	15.0	54	76.1		553.6	1,813		83.5																											
1973	102.3	480	58.5		636.5	3,012	58.0	33.9	142	65.5	874	15.0	54	76.1		587.6	1,942		82.9																											
1974	106.7	504	58.0		669.9	3,171	57.9	32.0	135	65.0	909	15.0	54	76.1		622.9	2,073		82.3																											
1975	111.5	529	57.7		703.9	3,334	57.9	30.4	128	65.1	945	15.0	54	76.1		658.5	2,207		81.7																											
1976	115.3	547	57.7		733.9	3,468	57.8	28.6	122	64.1	1,004	5.3	-	-		700.0	2,342		81.8																											
1977	119.2	570	57.3		765.8	3,631	57.8	27.0	115	64.3	1,028	-	-	-		738.8	2,488		81.3																											
1978	123.2	592	57.0		798.7	3,791	57.7	25.7	110	64.0	1,042	-	-	-		773.0	2,639		80.3																											
1979	127.6	616	56.7		833.1	3,957	57.7	24.2	104	63.9	1,094	-	-	-		808.9	2,759		80.3																											
1980	131.9	637	56.7		870.1	4,122	57.8	22.7	98	63.4	1,135	-	-	-		847.4	2,889		80.3																											
1981	136.8	663	56.5		902.8	4,290	57.7	21.4	93	63.0	1,190	-	-	-		881.4	3,007		80.3																											
1982	142.0	690	56.4		937.4	4,452	57.7	20.1	88	62.6	1,239	-	-	-		917.3	3,125		80.4																											
1983	147.5	718	56.3		972.9	4,622	57.6	18.9	84	61.6	1,289	-	-	-		954.0	3,249		80.4																											
1984	153.2	745	56.3		1009.6	4,781	57.8	17.6	79	60.9	1,330	-	-	-		992.0	3,372		80.6																											
1985	159.0	776	56.2		1049.0	4,980	57.6	16.4	74	60.8	1,393	-	-	-		1032.6	3,513		80.6																											
1986	165.7	798	56.2		1044.1	5,148	57.7	15.1	69	60.0	1,447	-	-	-		1089.3	3,632		80.6																											
1987	168.7	824	56.1		1120.5	5,323	57.6	14.5	66	60.2	1,500	-	-	-		1106.0	3,757		80.6																											
1988	173.9	847	56.1		1156.9	5,482	57.7	13.8	63	60.0	1,545	-	-	-		1113.1	3,874		80.7																											
1989	179.2	874	56.1		1193.7	5,678	57.6	13.3	61	59.8	1,612	-	-	-		1180.4	4,005		80.7																											
1990	184.6	901	56.1		1230.4	5,859	57.5	12.7	58	60.0	1,672	-	-	-		1217.7	4,129		80.8																											
1991	190.2	928	56.1		1263.7	6,022	57.5	12.2	56	59.7	1,725	-	-	-		1251.5	4,241		81.0																											
1992	195.9	951	56.1		1297.0	6,173	57.5	12.0	55	59.8	1,769	-	-	-		1285.0	4,349		81.0																											
1993	201.9	984	56.1		1330.8	6,359	57.4	11.8	54	59.9	1,838	-	-	-		1319.0	4,467		80.9																											
1994	207.9	1,013	56.1		1364.8	6,532	57.4	11.0	50	60.3	1,897	-	-	-		1353.8	4,585		80.9																											
Total	3952.1																24,794.4																													

\* Total British Columbia requirements less East Kootenay requirements, to be served by reserves from British Columbia and the Peace River region of Alberta.

\*\* To be served by Alberta reserves excluding those in the Peace River region.





5. Figures in Column 6 were obtained by multiplying Column 4 by Column 5.
6. Figures for total gas in place necessary to meet requirements, shown in Column 7, were obtained by adding the values in Columns 3 and 6.
7. The ratios of marketable gas to gas in place, shown in Column 8, were obtained from the field data submitted during the hearing and are weighted averages.
8. Figures for marketable gas necessary to meet requirements, shown in Column 9, were obtained by multiplying Columns 7 and 8.
9. The established reserves required, shown in Column 10, are the values shown in Column 9 for all cases except the 30-year periods for Canadian requirements. Column 10 shows the requirement of Canadian markets for 21 years to be met from established reserves, whereas the amount of reserves over and above these which will be necessary for the 30-year period are shown in Column 11 to be forthcoming from future reserves. For example, total 30-year requirements for British Columbia (net) are 6,082 Bcf (Line 2, Column 9) of which 2,161 Bcf are to be supplied from established reserves (Line 1, Column 10), whereas 3,921 Bcf (Line 2, Column 11) are to be supplied by future reserves. All 21-year requirements are to be supplied from established reserves.
10. The requirement of Canadian-Montana's existing export licence GL-8, shown on Line 8, was not provided with terminal peak-day protection. This is consistent with the Board's report of 13 October 1961, wherein maximum daily and annual rates were designated "to permit flexibility in the Applicant's operations". This is also consistent with the treatment given by the Alberta Board.

**FUTURE NATURAL GAS REQUIREMENTS OF CANADA PLUS EXPORT COMMITMENTS  
AND THE ESTIMATED RESERVES NECESSARY TO SUPPLY THESE REQUIREMENTS**  
**1,000 BTU'S PER CUBIC FOOT**

(1) <u>Market Area</u>	(2) <u>Period of Requirement</u>	(3) Deliveries During Period To Meet Estimated Demand BCF	(4) Terminal Peak Day Rate F n	(5) Corrected Reserves Delivery Ratio CF	(6) Reserves Required For Terminal Peak BCF n	(7) Total Gas In Place Necessary To Meet Requirements BCF	(8) Ratio of Marketable Gas To Gas In Place k	(9) Marketable Gas Necessary To Meet Requirements BCF	(10) Established Reserves Required BCF	(11) Future Reserves BCF
1) British Columbia (net)	1 Jan/65 to 31 Dec/85	(A) 1,467	339	3.0	1,017	2,484	0.87	2,161	2,161	- (1)
12) British Columbia (net)	1 Jan/65 to 31 Dec/94	3,952	1,013	3.0	3,039	6,991	0.87	6,082	-	3,921 (2)
(1) East Kootenay	1 Jan/65 to 31 Dec/85	(A) 58	14	5.6	78	136	0.85	116	116	- (3)
(4) East Kootenay	1 Jan/65 to 31 Dec/94	128	33	5.6	185	313	0.85	266	-	150 (4)
(5) Alberta	1 Jan/65 to 31 Dec/94	10,566	2,580	3.4	8,772	19,338	0.85	16,437	11,437	5,000 (5)
6) Canada, East of Alberta (net)	1 Jan/65 to 31 Dec/85	(A) 8,014	1,251	3.8	4,756	12,768	0.85	10,853	10,853	- (6)
(7) Canada, East of Alberta (net)	1 Jan/65 to 31 Dec/94	24,794	4,585	3.8	17,423	42,217	0.85	35,884	-	25,031 (7)
(8) Canadian-Montana GL-8 (Aden)	1 Jan/65 to 14 May/74	152	-	-	-	-	-	-	152	- (8)
17) Westcoast Transmission (Sumas)	1 Jan/65 to 2 Oct/77	1,322	309	3.0	927	2,249	0.87	1,957	1,957	- (9)
(9) Alberta & Southern GL-3 (Kingsgate)	1 Jan/65 to 31 Oct/86	3,597	482	4.3	2,073	5,670	0.84	4,763	4,763	- (10)
11) Canadian-Montana GL-5 (Cardston)	1 Jan/65 to 31 Oct/86	254	37.8	4.3	160	414	0.84	348	348	- (11)
10) Niagara Gas Trans. GL-6 (Cornwall)	1 Jan/65 to 30 June/80	70	16.8	3.8	64	134	0.85	114	114	- (12)
3) Trans-Canada GL-1 (Emerson)	1 Jan/65 to 14 May/81	1,147	224	3.8	851	1,998	0.85	1,698	1,698	- (13)
4) Westcoast GL-4 (Kingsgate)	1 Jan/65 to 10 Dec/81	963	163	5.6	913	1,876	0.85	1,595	1,595	- (14)
14) Trans-Canada GL-2 (Niagara)	(C) to 31 Dec/65	-	-	-	-	-	-	(C)	-	- (15)
Total								34,194	34,102	

(A) Leveled after 1968 at 1968 rate.

(B) Two years trends for Alberta requirements as per Alberta Board report.

(C) Licence is for seller's option interruptible gas, with no quantities specified.





NOTES TO ACCOMPANY APPENDIX 3, TABLE 5

This table shows the amount of reserves required for export and for protection of the peak day in the terminal year of such export for the three applicant companies.

1. In the cases of Alberta and Southern and of Canadian-Montana, the presentation reflects the licence in the form which the Board proposes to grant, rather than the form in which the applications were made. For example, Alberta and Southern applied for a maximum quantity "which when added to the quantity that may be contemporaneously exported under authority of and in accordance with licence GL-3 shall produce" 5,900,000,000,000 cubic feet during the term of the licence. Under its existing licence GL-3, Alberta and Southern is permitted to export a total of 3,826,000,000,000 cubic feet. The additional amount requested by the Applicant was 2,074,000,000,000 cubic feet. As discussed under the "Supply" heading in Section 5 of this report, the Board has determined the amounts which it is prepared to authorize by subtracting the amount of the existing export licence GL-3 from the volumes of the application for the last three years of the application. Under GL-3 Alberta and Southern is authorized to remove 153,270,000,000 cubic feet in any consecutive 12-month period. Accordingly, the Board has reduced the total amount set forth in the application by 460,000,000,000 cubic feet, resulting in a total amount of 1,614,000,000,000 cubic feet to be authorized. This is the amount entered in Column 2 as the export quantity for the entire period.

Canadian-Montana's application was treated in a similar manner.

2. Column 3 lists the weighted average of heating values for the fields from which the Applicants propose to take gas, after such gas has been processed.
3. Column 4 shows the export quantities in terms of 1,000-Btu gas, obtained by multiplying Columns 2 and 3, and dividing by 1,000.
4. Column 5 is the terminal date of the licence requested by the Applicants.
5. Column 6 lists the terminal peak-day rate based on the Applicants' submission and adjusted for heating value. As noted under (1) above the quantities for the terminal three years of Alberta and Southern's and Canadian-Montana's applications have been reduced.



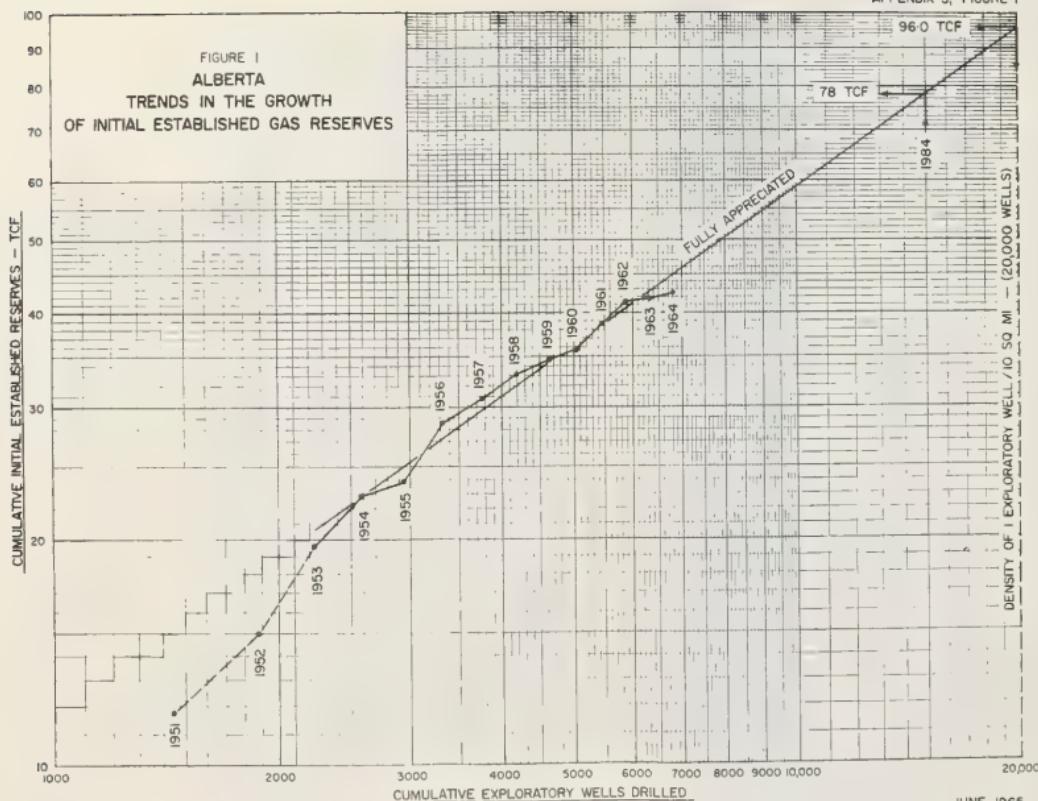
6. Column 7 shows the corrected reserve/deliverability ratios (CF) obtained from the deliverability schedules for the Applicants' gas reserves.
7. Column 8 lists the reserves required for terminal peak-day protection, obtained by multiplying Columns 6 and 7.
8. Column 9 lists the total gas in place required to meet the licence requirements, obtained by adding Columns 4 and 8.
9. Column 10 lists the ratios of marketable gas to gas in place, which ratios are weighted averages of the ratios for fields from which the Applicants will remove gas.
10. Column 11 lists the marketable gas reserves necessary to serve the licences under consideration. These reserves were obtained by multiplying Columns 9 and 10.

(A)  
ESTIMATED RESERVES NECESSARY TO SUPPLY NATURAL GAS REQUIREMENTS

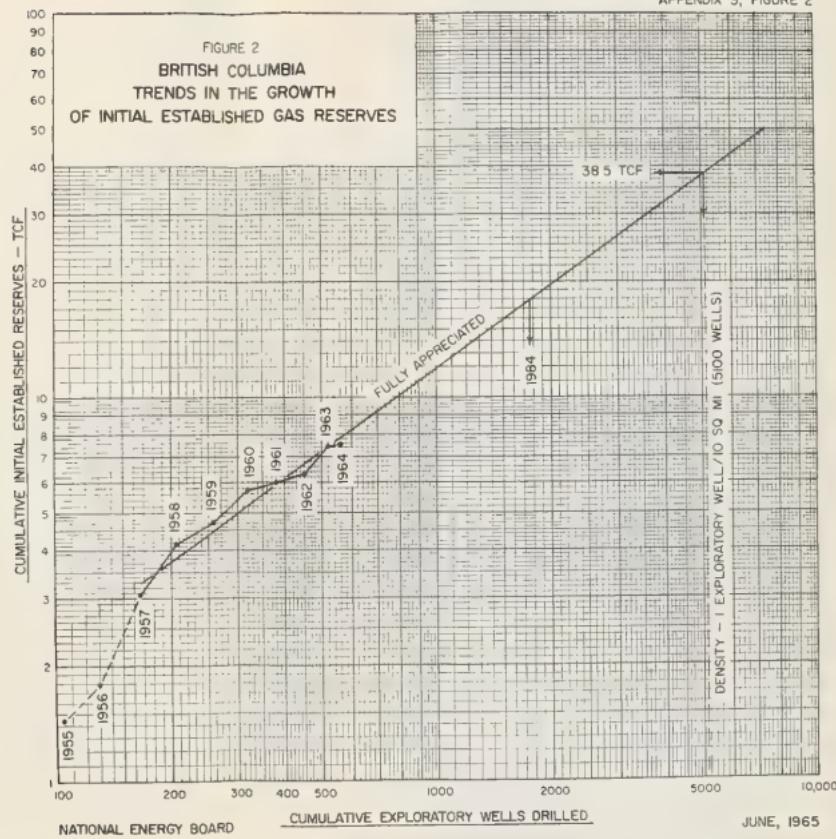
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Applicant	Export Quantity for Entire Period	BTU per Cubic Foot of Gas Available to Applicant	Equivalent Export Quantity at Standard Conditions	Terminal Date of Requested Export Licence	Terminal Peak Day Rate P <sub>n</sub>	Corrected Reserves Delivery Ratio CP	Reserves Required for Terminal Peak CPP <sub>n</sub>	Total Gas in Place Required to Meet Licence	Ratio of Marketable Gas to Gas in Place K	Marketable Gas Necessary to Meet Licence Proposed
	BCF	BCF	BCF		MMCFD	BCF/MMCFD	BCF	BCF	BCF/BCF	BCF
{1) Alberta and Southern (Kingsgate)	1,614	1,050	1,695	31 Oct. 1989	237	4.3	1,019	2,714	0.34	2,280
{2) Canadian-Montana (Cardston)	110	1,050	116	31 Oct. 1989	25	4.3	108	224	0.44	188
{3) Trans-Canada (Emerson)	1,700	1,004	1,707	31 Oct. 1990	187	3.8	711	2,418	0.85	2,055

(A) Columns (4) to (11) at 1,000 BTU's per Cubic Foot

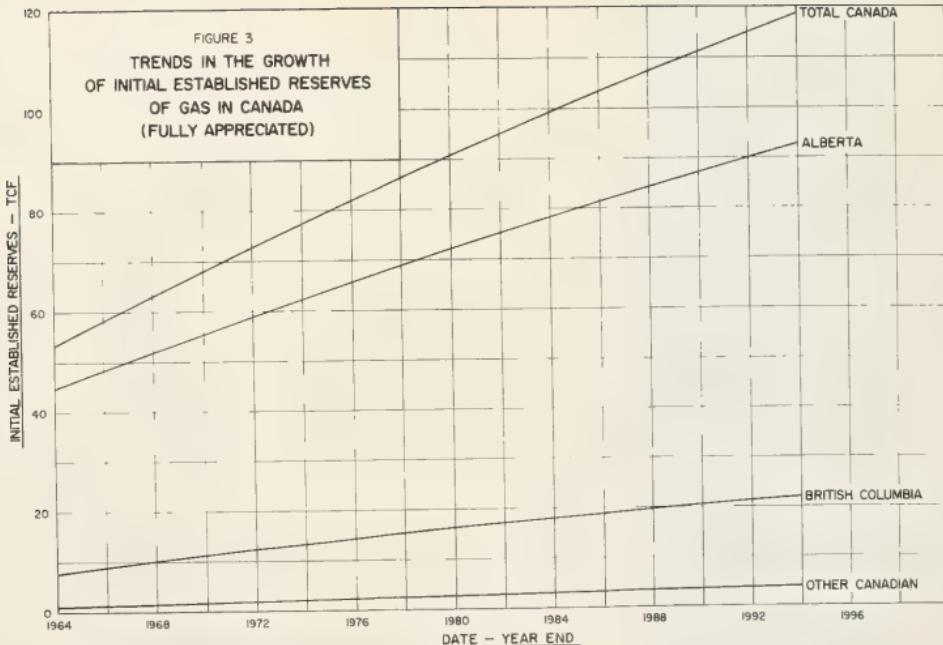
















NATIONAL ENERGY BOARD

ALBERTA NATURAL GAS COMPANY

MAP SHOWING PIPE LINE ROUTE  
INCLUDING 1965 CONSTRUCTION

1965 CONSTRUCTION

NEW COMPRESSOR STATION  
ADDITION TO EXISTING COMPRESSOR STATION

SCALE: 1" = 8 MILES

DRAWN BY: H.O.  
CHECKED BY: C.R.K.  
APPROVED BY: J.A.NATIONAL ENERGY BOARD  
OTTAWA JUNE 1965

DRAWING NO. 2099 - M



NATIONAL ENERGY BOARD

**MAP OF INTERCONNECTING  
MAJOR GAS PIPE LINE SYSTEMS  
IN WESTERN CANADA  
AND UNITED STATES**

2098 - M

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